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HEAT RECOVERY AND ENVIRONMENTAL IMPACTS OF FLUE GAS CONDENSING

Master's thesis for the degree of Master of Science in Technology
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Abstract of master's thesis

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Abstract

The objective of this thesis is to study effects of flue gas condensing (FGC) on heat recovery and the environment by thermodynamic calculations using data from the literature.

The latest version of the large combustion plant (LCP) best available technique (BAT) reference document (BREF) from June 2013 introduces new BAT, associated emission levels (BAT-AELs) for emissions to air and to direct water discharge. These BAT-AELs add pressure to energy producers to find solutions to meet the new requirement and FGC is one considerable choice. FGC is an efficient way to reduce most of the flue gas emissions, but also forms additional condensate stream and, moreover, affects the flue gas emission dispersion, which in turn requires a new stack design. Based on literature data, the flue gas emissions of a reference combined heat and power (CHP) plant in Rauma are evaluated and simulated by using the flue gas dispersion model.

FGC is also used for flue gas heat recovery purposes. Most of the energy content in flue gases is present in the form of latent heat, which can be utilized for the preparation of district heating (DH) water. This heat recovery can be enhanced with heat pump or combustion air humidifier (CAH) attached to the FGC. In the thesis, potentials for these methods are calculated and one year simulation is done with real plant data while plant runnability is taken into account. Based on these premises and information from literature, effects on the CHP plant mass and energy balance are determined and economical aspects are evaluated.

Results show that FGC has the potential to reduce emission and allows heat recovery. The FGC should be able to reduce most of Rauma's CHP plant emissions, thus meeting the new requirement for emissions to air. FGC heat recovery lowers the annual fuel consumption when boiler is operated based on DH demand, but it also lowers power production. Overall, FGC is shown to be a profitable choice for emission reductions and heat recovery.

Keywords Flue gas, heat recovery, condensing, simulation, combustion air humidifier, heat pump, enviromental impacts, dispersion modeling, CHP plant, economy

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Abstract of master's thesis

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Työn nimi Savukaasun lauhdutuksen lämmöntalteenotto ja ympäristövaikutukset

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Tiivistelmä

Työn tarkoituksena on tutkia savukaasun lauhdutuksen (FGC) vaikutusta ympäristöön ja lämmöntalteenottoon laskujen ja alan kirjallisuuden kautta.

Uusin versio suurien polttolaitosten (LCP) parhaan käyttökelpoisen tekniikan (BAT) referenssi dokumentin (BREF) kesäkuun 2013 luonnoksesta esittää uusia BAT – päästötasoja (BAT-AELs) savukaasulle ja laitosten poistovedelle. Tämä painostaa energiateollisuutta etsimään ratkaisuja uusien päästötasojen täyttämiseksi ja tähän FGC on yksi varteenotettava ratkaisu. FGC puhdistaa suurimman osan savukaasun päästöistä tehokkaasti, mutta se myös luo uuden lauhdevirtauksen ja vaikuttaa savukaasun leviämiseen ja piippuun. Työssä näitä asioita on tutkittu kirjallisuuden kautta ja karkea lemiämismallinnus on tehty Rauman sähkön ja lämmön yhteistuotantolaitokselle.

FGC:tä voidaan käyttää myös lämmöntalteenottoon savukaasusta. Suurinosan savukaasun energiasta on latenttilämpöä jota voidaan hyödyntää kaukolämpöveteen FGC:llä. Tätä lämmöntalteenottoa voidaan parantaa liittämällä lämpöpumppu tai palamisilman kostutin FGC:hen. Työssä näiden menetelmien potentiaaleja on laskettu ja simuloitu oikealla datalla laitoksen ajettavuus huomioden. Näistä lähtökohdista ja kirjallisuudesta, FGC:n vaikutuksia Rauman laitoksen massa- ja energiataseeseen on laskettu ja taloudellisuutta arvioitu.

Tulosten mukaan FGC:llä on potentiaalia päästöjen puhdistukseen ja lämmöntalteenottoon savukaasuista. FGC:n piätisi pystyä täyttämään useimpien päästöjen uudet BAT-AEL päästötasot savukaasulle. FGC:n lämmöntalteenotto laskee vuosittaista polttoaineenkulutusta kun kattilaa ajetaan kaukolämpö tarpeen mukaan, mutta se laskee myös sähköntuotantoa. Kaiken kaikkiaan FGC näyttäisi olevan taloudellinen ratkaisu päästötasojen täyttämiseen ja lämmöntalteenottoon.

Avainsanat Savukaasu, lämmöntalteenotto, lauhdutus, simulaatio, palamisilman kostutin, lämpöpumppu, ympäristövaikutukset, leviämismallinnus, CHP laitos, taloudellisuus

ALKUSANAT

Tämä diplomityö on tehty Pohjolan Voima Oy:lle Helsingissä maaliskuun 2015 – marraskuun 2015 välisenä aikana.

Haluan kiittää Pohjolan Voima Oy:tä työn ajankohtaisesta ja mielenkiintoisesta aiheesta. Lisäksi kiitän erityisesti Valmet Power Oy:n DI Laura Kuukkasta diplomityön ohjaamisesta ja Hervannan lämpölaitoksen esittelystä. Haluan kiittää myös kaikkia diplomityössä mukana olleita niin Pohjolan Voima Oy:ltä kuin Aalto-yliopistolta asiantuntevista palautteista ja kommenteista. Kiitän myös Rauman Biovoima Oy:n toimitusjohtaja DI Timo Pitkästä kärsivällisyydestä ja laskujen mahdollistamisesta. Raumalle myös kiitokset Mika Korteniemelle havainnollistavasta laitosesittelystä. Kiitokset kuuluu myös TkT Sanna Hellstenille työn perusteellisesta oikoluvusta.

Haluan kiittää myös läheisiäni ja ystäviäni tuesta ja kannustuksesta opiskelujeni ajalta.

Helsingissä 9 marraskuuta 2015

Juuso Uotila

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LIST OF SYMBOLS

ρ_h = partial density of water (kg/m^3)

ρ_g = partial density of dry gas (kg/m^3)

σ_y = standard deviation of emission concentration distribution in horizontal direction (m)

σ_z = standard deviation of emission concentration distribution in vertical direction (m)

Δh = plume rise (m)

C(x,y,0,H) = ground level concentration according to Gaussian plume model

C_n = cash flow of year n (€)

COP = coefficient of performance

c_p = heat capacity of the flow (kJ/kgK)

$c_{p,dg}$ = heat capacity of dry flue gas (kJ/kgK)

$c_{p,i}$ = heat capacity of component i (kJ/kgK)

$c_{p,m}$ = heat capacity of mixture (kJ/kgK)

$C_{p,v}$ = heat capacity of water vapor (kJ/kgK)

$c_{p,w}$ = heat capacity of water (kJ/kgK)

$c_{p,wg}$ = heat capacity of wet flue gas (kJ/kgK)

D = stack inside diameter (m)

dT = temperature difference between cold and hot side ($°C\ or\ K$)

g = gravity acceleration (m/s^2)

H = effective stack height (m)

H,h = enthalpy of latent heat (kJ/kg)

H,i = enthalpy of sensible heat (kJ/kg)

H,k = total enthalpy (kJ/kg)

H,k1 = total enthalpy of flue gas inlet (kJ/kg)

H,k2 = total enthalpy of flue gas outlet (kJ/kg)

IC = investment cost (€)

l = heat of phase transition (kJ/kg)

m = mass flow (kg/s)

M = molar mass of mixture (g/mol)

m_{cond} = water condensed (kg/s)

m_{dg} = dry flue gas mass flow (kg/s)

M_{dg} = molar mass of dry flue gas (g/mol)

m_{dh} = DH water mass flow (kg/s)

m_{fg} = flue gas mass flow (kg/s)

M_g = molar mass of dry gas (g/mol)

M_h = molar mass of water vapor (g/mol)

M_i = molar mass of component I (g/mol)

$m_{mo,1}$ = initial moisture (kg/s)

$m_{mo,2}$ = moisture content after humification (kg/s)

$m_{mo,i}$ = moisture increased (kg/s)

M_{wg} = molar mass of wet flue gas (g/mol)

NCF = yearly net cash flow (€)

NPV = net present value (€)

P = heat transfer output (kW)

P = stability class factor (0.3 for D)

P_0 = total pressure of the system (Pa)

p_g = partial pressure of gas (Pa)

p_h = partial pressure of water (Pa)

p_h = the partial pressure of water in the flue gas (Pa)

p_h' = the saturated steam pressure in the flue gas (Pa)

PT = payback time (€)

Q = heat pumped (kW)

Q = source emission rate (µg/s)

U = wind speed at stack height (m/s)

R = gas constant (J/Kmol)

r = internal rate of return (%)

R = stack radius (m)

T = source temperature (K)

T = temperature of the system (℃)

T_A = ambient temperature (K)

$T_{dew\ point,1}$ = initial dew point (℃)

$T_{fg,in}$ = flue gas temperature in inlet (℃)

$T_{fg,out}$ = flue gas temperature in outlet (℃)

T_{ref} = reference temperature (℃)

T_{return} = DH return water temperature (℃)

T_{supply} = DH supply water temperature (℃)

U_0 = wind speed at anemometer height (m/s)

V = stack exit velocity (m/s)

W = power demand of the heat pump (kW)

w_{CO2} = weight fraction of carbon dioxide in mixture

w_{H2O} = weight fraction of water in mixture

w_i = weight fraction of component i

w_{N2} = weight fraction of nitrogen in mixture

w_{O2} = weight fraction of oxygen in mixture

x = absolute moisture (kg/kg_{dry})

x = distance downwind from the stack (m)

x* = distance to determine maximum plume rise (m)

x_1 = initial absolute moisture content (kg/kg_{dry})

x_2 = absolute moisture after humidification (kg/kg_{dry})

x_{dec} = absolute moisture content decreased (kg/kg_{dry})

x_i = molar fraction of component I

y = distance crosswind from the plume centerline (m)

Z = desired height (stack height) (m)

Z_0 = anometer height (m)

∂ = relative humidity (%)

ABBREVIATION

AEEL = Associated energy efficiency level

AEL = Associated emission level

BAT = Best available technique

BFB = Bubbling fluidized bed

BHF = Bag house filter

BREF = BAT reference document

CAH = Combustion air humidifier

CEMS = Continuous emission monitoring system

CHP = Combined heat and power

COD = Chemical oxygen demand

COP = Coefficient of performance

DH = District heating

ELV = Emission limit value

ESP = Electrostatic precipitator

FGC = Flue gas condensing

HHV = Higher heating value

HP = High pressure

IED = Industrial emission directive

IPPC = Integrated pollution prevention and control

IRR = Internal rate of return

LCP = Large combustion plant

LHV = Lower heating value

MF = Microfiltration

NF = Nanofiltration

RO = Reverse osmosis

SCR = Selective catalytic reduction

SNCR = Selective non-catalytic reduction

TOC = Total organic carbon

TSS = Total suspended solids

UF = Ultrafiltration

1. INTRODUCTION

Industrial emissions directive (IED) for combustion plants forces energy producers to make new investements to environmental technologies. These technologies usually involves investment costs, which are burden to the companies. However benefits can also be gained. Combined heat and power (CHP) production is usually designed to maximize overall efficiency. This could further be improved with flue gas condensing (FGC). FGC improves the overall efficiency by utilizing both sensible and latent heat of flue gas, which otherwise is released into the atmosphere [**1**].

Environmental permit determines emission limits that a plant can release to the environment [**2**]. IED and best available technique (BAT) reference document (BREF) tightens these limits and FGC could be used to achieve the new limits. In FGC some of emissive components are dissolved from flue gas to condensate. Since the environmental permit sets limits also for the liquid emissions, the condensate must typically be treated [**3**].

The FGC has significant effects on flue gas properties, and consequently it affects also the emission dispersion [**4**]. As known, cool gas does not rise as high as hot gas. The change in the flue gas temperature may affect the optimal stack height, even though the gas is now cleaner. After the FGC flue gas is below the acid dew point, which must be taken into account when selecting the materials for the stack, ducts and auxiliaries [**5**].

This thesis focuses on the effects of FGC to heat recovery and environment from investment decision standpoint. The thesis is done for Pohjolan Voima Oy reference plant in Rauma to determine the effects of FGC to the environment and to the energy balance of the plant via heat recovery. The research is based on literature reviews and calculations.

1.1. Research questions and confining

This thesis tries to answer the following research questions, which will be evaluated in the end:

1. What are the environmental effects of FGC?
2. What kind of possibilities are there for heat recovery from flue gas?
3. How does heat recovery affect the CHP plants overall balance and operation in theory?
4. How FGC could be connected to boiler HK 6 in Rauma and what would be the effects on CHP plant overall balance in practice?

THEORY PART

2. ENVIRONMENTAL EFFECTS

In this section the environmental effects of FGC are being reviewed, considering also the regulations and technologies linked to FGC.

2.1. New regulations, IED, BREF documents

New regulations are being drafted by IED, which is successor of integrated pollution prevention and control (IPPC) directive. The purpose of the directive is to mimize pollution from various industrial sources in European Union through legislation. The directives new emission limit values (ELVs) are based on BAT, determined via information exchange between experts from EU member states. New BREF is being drafted and it is expected to be ready in begin of 2017 [**6**,**7**]. Drafts latest version ELVs for the emissions to air are tabulated in table 1 [**8**] and those fore the emissions in water discharges in table 2 [**3**]. These ELVs are of major importance, because they contributes to the new environmental permit limits, which plants must fulfill [**7**]. BREF also defines the efficiencies, in which the plants should operate (table 3) [**9**].

*Table 1. Drafts latest version BAT – associated emission levels (BAT-AELs) to air for 100 – 300 MW existing solid biomass and/or peat fired plant (6% Oxygen) [**8**].*

mg/Nm3	Hg	Dust ([1])	SO_2 ([1])	HCl	HF([3])	NO_x ([1])	CO ([1])	NH_3 ([4])
Yearly min	< 0.001	2	<10	1 ([3])		50	30	3
Yearly max	0.005	12	70 ([2])	9 ([1, 3, 5])	<1	180	160	10 ([6])

([1]) These BAT-AELs do not apply to combustion plants operated less than 1500 h/yr., excluding existing CCGT.
([2]) For existing plants burning fuels where the average sulphur content is 0.1 % or higher, the higher end of the BAT-AEL range is 100 mg/Nm3.
([3]) The lower end of these BAT-AEL ranges may be difficult to achieve in the case of plants fitted with a wet FGD system and a downstream gas-gas heater
([4]) Ammonia BAT-AELs emissions are only associated with the use of SCR and/or SNCR. The lower end of the range can be achieved when using SRC and the upper end of the range can be achieved when using SNCR without wet abatement techniques
([5]) For plants burning fuels where the average Cl content is ≥ 0,1 wt-% (dry) or for existing plants co-combusting biomass with sulphur-rich fuel (e.g. peat) or using alkali chloride-converting additives (e.g. elemental sulphur), or for plants with an average Cl content in the fuel of < 1 500 h/yr., the higher end of the BAT-AEL range for the yearly average for existing plants is 25 mg/ Nm3 and for new plants 15 mg/ Nm3. For existing plants with an average Cl content in the fuel of ≥ 0,1 wt-% (dry) operated < 1 500 h/yr., the higher end of the BAT-AEL range for yearly average is 50 mg/ Nm3.
([6]) In the case of combustion plants firing biomass and operating at variable load and in the case of engines firing HFO/gas oil, the higher end of the range is 15 mg/Nm3

*Table 2. Drafts latest version BAT-AELs for direct discharges to a receiving water body from flue-gas treatment [**3**].*

Component		**Unit**	**BAT-AEL**
Total organic carbon (TOC)		mg/l	20 - 50 ([1])
Chemical oxygen demand (COD)		mg/l	60 - 150 ([1])
Total suspended solids (TSS)		mg/l	10 - 30
Fluoride (F^-)		mg/l	10 - 25
Sulphate (SO_4^{2-})		g/l	1.3 - 2 ([2]) ([3])
Sulphide (S^{2-}), easily released		mg/l	0.1 - 0.2
Sulphite (SO_3^{2-})		mg/l	1 - 20
Metals and metalloids	**As**	µg/l	10 - 50
	Cd	µg/l	2 - 5
	Cr	µg/l	10 - 50
	Cu	µg/l	10 - 50
	Hg	µg/l	0.5 - 5
	Ni	µg/l	10 - 50
	Pb	µg/l	10 - 20
	Zn	µg/l	50 - 200
([1]) Either the BAT-AEL for TOC or The BAT-AEL for COD applies. TOC monitoring is preferred option, because it does not rely on the use of very toxic compounds **([2]) The BAT-AEL only applies to plants using calsium compounds in flue-gas treatment** ([3]) The upper end of the range may not apply in the case of high salinity of the waste water due to the increaesd solubility of calsium suplhate.			

*Table 3. Drafts latest version BAT- associated energy efficiency levels (BAT-AEELs) for existing plants burning biomass and/or peat [**9**].*

BAT-AEELs in lower heating value (LHV) basis ([1])([4])	
Net electrical efficiency (%) ([2])	**Net total fuel utilisation (%) ([3])**
28 - 38	73 - 99
([1]) These BAT-AEELs do not apply in the case of units operated < 1500 h/yr. ([2]) Within the given BAT-AEEL ranges the achieved energy efficiency can be negatively affected (up to four percentage points) by the type of cooling system used or the geographical location of the combustion unit ([3]) These levels may not be achievable in the case of an excessively low potential heat demand **([4]) In the case of CHP units, only one of the two BAT-AEELs 'Net electrical efficiency' or 'Net total fuel utilisation' applies, depending on the CHP unit design (i.e. either more oriented towards electricity or towards heat generation)**	

2.2. Flue gas emissions

Flue gas composition determines the emissions to air. The composition of the flue gas is affected by plant equipments, boiler and fuel used. In combustion, components of fuel (table 4) are released to flue gas [**10**].

*Table 4. Solid fuel chemical compositions [**11**].*

Property	**Woodchips**	**Bark**	**Sawdust**	**Peat**	**Coal**
Moisture %	45 - 55	50 - 60	50 - 60	45 - 55	10
Ash % (d)	0.5 - 2	1 - 3	0.5 - 1	6	14
Volatiles % (d)	80 - 90	70 - 80	70 - 80	64 - 70	30
Carbon % (d)	52	55	50	54	72
Hydrogen % (d)	6	6	6	5.5	4.5
Nitrogen % (d)	<0.5	<0.5	<0.5	1.7	1
Sulfur % (d)	<0.05	<0.05	<0.05	0.2	<1.0
Oxygen % (d)	40	37	43	33	8
Chlorine % (d)	<0.05	<0.05	<0.05	<0.05	<0.1

Fuel components are being combusted in the boiler forming components like carbon dioxide (CO_2), sulfur oxides (SO_x) and nitrogen oxides (NO_x) to flue gas. These

reactions produce heat and to maximize the heat produced, excess combustion air is fed to the boiler furnace. However small amounts of incomplete combustion products such as carbon monoxide (CO) and volatile organic componds (VOC) are being formed [**12**]. Hydrogen fluoride (HF) and hydrogen chloride (HCl) are formed from fluoride and chloride sources of the fuel [**13**,**14**]. Ammonia (NH_3) is also present in the flue gas, but it is orginated mostly from NO_x reduction technologies [**15**,**16**]. Other fuel components such as different metals are being transformed to fly ash in the boiler. The fly ash is composed mainly of alumina (Al_2O_3), silica (SiO_2), ferric oxide (Fe_2O_3), copper oxide (CuO) and calcium oxide (CaO) [**17**]. The final composition of flue gas depends on moisture content, boiler, fuel and treatment technologies used, but for biomasses some implication can be seen from table 5 [**18**].

*Table 5. Typical flue gas component concentrations from burning of biomasses in 6% oxygen with ammonia slip from SNCR, converted from sources [**19**,**20**,**21**].*

Component	**mg/Nm^3**
SO_2	28 - 113
NO_x	150 - 506
HCl	2 - 150
CO	15 - 1500
Particles	56 - 468
Heavy metals	30 - 150
NH_3	10 - 15
TOC	8 - 19
HF	0.15 - 0.38

Acidic rains became a considerable public concern in the 1970s and 1980s, when they caused environmental damage to forests and surface waters. The acid rains were mainly caused by sulfur and nitrogen dioxide emissions, which were not cleaned from flue gases at the time [**22**]. Nowadays air quality is better, because of the cleaning technologies are utilized and acid rains rarely occur [**23**,**24**]. When sulfur dioxide is released to atmosphere, it reacts with water and forms sulfuric acid. The same happens with nitrogen oxides forming nitric acid [**25**]. Other flue gas compounds that may induce acid rainds are hydrogen chloride and ammonia, from which ammonia is

base but may react and form nitric acid [**12**]. For large combustion plants (LCP), these emissions are being focused on [**3**].

2.2.1. Dry cleaning and other technologies

Most common dry flue gas cleaning technologies are electrostatic precipitators (ESP) and bag house filters (BHF). These technologies are used prior to FGC unit to reduce particles and dust content in the flue gas, but BHF can be modified to remove also acidic compounds.

In ESP, flue gas particles are ionized to gain electric charge. Charged particles are then pushed trough plates with opposite charge that attracts them towards the plate [**26**,**27**]. ESP is sensitive to electrical resistivity and size distribution of particles, which can limit its application to some processes.

In BHF the flue gas is sucked through filter bags and the particles are left to the filter surface. Filters are being frequently cleaned using pressurized air, and the ash is collected and pneumatically send to a fly ash silo [**28**,**26**]. ESP and BHF have both good separation efficiencies (ESP 95-99.9%, BHF 98-99.9%). ESP separation efficiency is at its lowest when the particle size is around 0.1-1 µm (90-99%). BHF can handle all particle sizes and cleaning can even be enhanced with chemical additives such as calciumhydroxide ($Ca(OH)_2$) or sodium bicarbonate ($NaHCO_3$), which bind hydrochloric acid, sulfur dioxide or hydrogenfluoride emissions. Also activated carbon can be added to BHF to bind heavy metals, furan and dioxin [**28**,**27**,**29**].

For NOx emissions selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can be used. These technologies uses sprayed ammonia to reduce NOx to nitrogen (N_2). SCR can be used in lower temperature than SNCR thanks to the presence of catalyst. It is also possible to design NOx scrubbers, in which the remaining NO is oxidized to NO_2 and then reduced to N_2 [**16**].

2.2.2. Flue gas condensing

FGC is done either in a condensing scrubber (figure 1) or in a tube condenser, or in variation of these two [**1**,**28**,**30**]. More acidic flue gasses are usually cleaned in scrubbers and less in tube condensers. Different chemicals additives may be used in the scrubbers to further reduce the emissions.

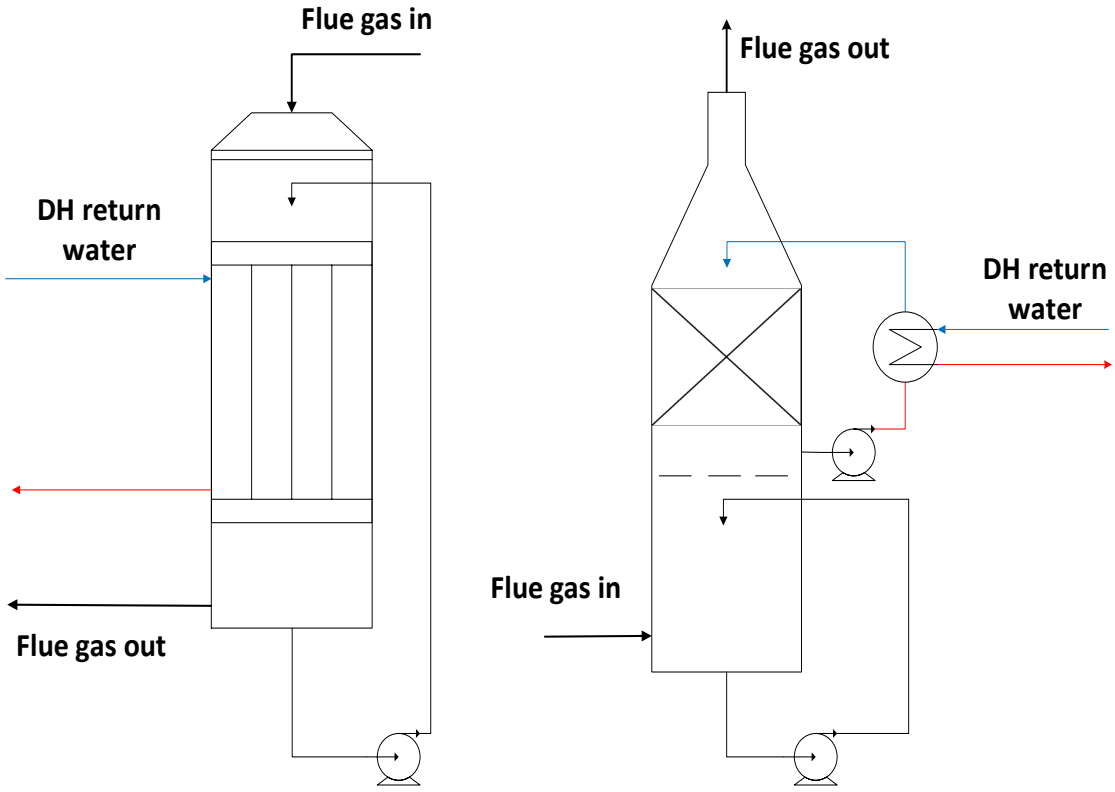
As seen in figure 2, flue gas feed is at bottom section of the scrubber. There it is pushed through a washing stage and then through a heat recovery stage [**31**,**32**]. Most of the emissions are transferred to circulation stream via absorption [**33**,**31**]. Packaging bed enhance contact area of flue gas and circulating stream, making heat recovery and absorption more efficient [**31**,**34**]. In a typical two stage scrubber the packaging bed is used for heat recovery purposes [**35**].

*Figure 1. Installed scrubber [**30**].*

Tube condensers (figure 2) are mainly used for heat recovery, but they can also handle the washing duty to some extent. In case there is lot of acidic gases and other emissions, the tube condenser needs a prewashing unit, where most of the acidic compounds of the flue gas are removed and the flue gas is moisturized. Without the prewashing, acidic components may corrode condenser surfaces. In the tube condenser, the feed is at the top and the flue gas runs through sprayed circulating

water and through condensing tubes that are typically cooled with return water from the district heating (DH) network [**1**,**35**]. Heat recovery in tube condensers is slightly better than in condensing scrubbers, because it occurs in a direct contact with cooling surfaces, whereas in the scrubber the final heat recovery occurs in a separate heat exchanger [**1**].

Figure 2. Tube condenser (left) and



*2-stage scrubber (right) [**1**,**28**].*

FGC is an efficient method for reducing emissions [**1**]. Earlier the main focus with FGC has been reduction of SO_2, but because of the incoming BREF emission levels, HCl and NH_3 are also stressed [**9**]. When the emissions are dissolved into the circulating stream, its pH is changed due to the acid reactions occuring [**25**,**35**].

The main reaction occurring in the FGC are [**25**,**35**]:

$$SO_2(g) + H_2O(l) \rightleftharpoons HSO_3^-(aq) + H^+(aq) \quad \{1\}$$

$$HCl(aq) + H_2O(l) \rightleftharpoons Cl^-(aq) + H_3O^+(aq) \quad \{2\}$$

$$HF(aq) + H_2O(l) \rightleftharpoons F^-(aq) + H_3O^+(aq) \quad \{3\}$$

$$NH_3(aq) + H_2O(l) \rightleftharpoons NH_4^+(aq) + OH^-(aq) \quad \{4\}$$

Most of the emissions are acidic, which decreases pH. In scrubber, the absorption of NH_3 and SO_2 is less efficient if pH is not controlled [**36**]. Reductions of different emissive components and their favorable pH, can be seen from table 6 [**3**,**35**]. To improve the SO_2 removal a base additive such as sodium hydroxide (NaOH) is typically added to the circulating stream. Since NH_3 and SO_2 favor different pH, it may be necessary to use a two stage scrubber if high concentrations of both sulfur dioxide and ammonia are present in flue gas.

*Table 6. Emissions reductions of FGC, +++ high reduction, + low reduction [**3**,**35**].*

Component	**Reduction**	**pH**
Sulfur oxides (SO_2)	+++	>5
Hydrogen chloride (HCl)	+++	NA
Hydrogen fluoride (HF)	+++	NA
Heavy metals	++	NA
Particles	++	NA
Ammonia (NH_3)	+++	<7
NA = not applicable		

Dust particles can also be reduced in the scrubber. Dust particles, unlike other emissions, are not absorbed to circulating stream, but transferred mainly through diffusion, interception and impaction [**37**]. Reduction efficiency for large size particles (>2µm) can reach over 90% [**31**]. On the other hand, the reduction in the amount of small particles is lower. It is common to use dry technologies as a pretreatment to reduce the solids content in the feed to FGC. When such pretreatment is used, the condensate quality is also better, which is beneficial later in the condensate treatment stage [**28**].

If heat recovery is connected to scrubber, emissions can be further decreased due to the lowered heat demand from boiler. This effect reduces fuel consumption and, therefore, total flue gas emissions are also decreased. The effect is significant (up to 30%) in situations, where CHP plant is being operated based on DH demand [**1**].

2.3. Condensate

When using FGC, approximately 1 m^3 of condensate is formed per 1 MWh of heat recovered [**1**]. Properties of the condensate are dependent on the flue gas properties and cleaning technologies utilized. The condensate consists mainly of particles that have passed through the flue gas treatment technologies prior to FGC and transfered to circulating stream [**28**]. This condensate cannot be directly discharged into the environment. Therefore, some condensate treatment is needed. The most suitable condensate treatment method depends on the composition of the condensate as well as on the requirements for the effluent, which are defined by the limitations of the techniques used for further treatment of the effluent and/or by the discharge limits [**35**]. In this section, these issues are being reviewed.

2.3.1. Condensate requirements

Requirements for water discharge will be tightened in the future by the incoming BREF [**3**,**38**]. Final emission levels for water discharge are yet to be decided, but it seems that the new BREF will have strict emissions levels for at least heavy metals and suspended solids. This will have an effect to environmental permits in due course. The selection and optimization of condensate treatment processes depends on the limits set by the environmental permit [**2**,**7**]. Nevertheless, the condensate quality (i.e., the nature and the concentration of harmful compounds in the condensate) has also a substantial impact on the selection of the most suitable treatment technology [**28**].

2.3.2. Condensate quality

Quality of condensate is determined by the flue gas properties as well as the flue gas treatment technologies prior to FGC and reduction efficiency of FGC. In table 7 condensate qualities are compared based on the dry and wet separation methods. In this example, FGC is performed in a typical two stage scrubber, in which washing is done in the lower stage and heat recovery in the upper stage.

*Table 7. Bioplant flue gas condensate quality after cleaning (*** large amounts, * low amounts in condensate) [**28**].*

Component	Unit	ESP	ESP	BHF	BHF
		Lower stage (washing)	Upper stage (heat recovery)	Lower stage (washing)	Upper stage (heat recovery)
pH		6-8	6-8	6-8	6-8
Solids	mg/l	***	**	*	*
Conductivity	mS/m	***	**	**	*
Alkalinity	mg/l	**	*	**	*
TOC	mg/l	*	*	*	*
Cl	mg/l	***	**	**	*
SO_4^{2-}	mg/l	***	**	**	*
SiO_2	mg/l	***	**	*	*
NH_3	mg/l	***	*	***	*
Al	mg/l	***	**	*	*
Fe	mg/l	***	**	*	*
Ca	mg/l	***	**	*	*
Mg	mg/l	**	**	*	*
Mn	mg/l	***	*	*	*
Na	mg/l	***	**	**	*
Heavy metals	µg/l	***	**	**	*

According to the table 7, BHF provides better reductions of different components than ESP; thus, the flue gas from BHF has lower emissions when entering to scrubber. The highest condensate quality is provided by the process in which BHF is used and condensate is taken from the heat recovery stage. Then most of the emissions are trapped to the washing stage circulation and only a small amount reaches the heat recovery stage, where it is taken for the treatment. However small stream must then

be taken from washing stage to prevent too high concentrations. This stream is often put to boiler, if environmental permit allows it, where it decreases the boiler efficiency slightly. When all condensate is taken from the washing circulation, the quality is reduced significantly. Condensate quality is also dependent on FGC usage rate, because the quality can vary highly based on the load. FGC is usually operated based on heat demand of DH network, meaning that lower amounts of circulating water are needed during warmer months, which leads to higher concentration of impurities in the condensate [**28**].

2.3.3. Condensate treatment technologies

Condensate formed in FGC is a mixture of water and different components such as solids, heavy metals and salts. Solids can be removed from the condensate with various technologie, e.g. filter bags, sand filters and lamella clarifiers. To separate heavy metals and salts, ion exchange or membrane technology can be used [**28**,**39**,**40**]. The principles of these technologies are described next.

Filter bags (figure 1) are simple filters, which remove solids by pushing water trough bag with certain filtration efficiency. This filtration efficiency can vary from micrometers to millimetres depending on the size of pores in the bag. Solids accumulate to the inside surface of the bag, meaning that the bag must be frequently changed [**41**,**42**].

*Figure 3. Filter bag demonstrated [**41**].*

Sand filters consists of fine sand and supporting gravel, which together form filtrating bed. Condensate is pushed through the bed by gravity or pumped with pressure, forming cleaned water as impurities are trapped to sand. Depending on the model, sand is back washed constantly or frequently. Washing water is typically treated with lamella or similar. Condensate quality after sand filter is affected by the bed thickness and coarserness of the sand. Filtration can be further enhanced and speeden up using flocculation chemicals that precipitates solids from the condensate. Impurities caught to sand layers can be removed by counter current rinsing [**40**,**43**]

For high amount of solids, lamella clarifiers can be used (figure 4). In a lamella clarifier, condensate is fed to a clarifier tank that contains a series of inclined plates. Solids settle onto these plates and fall down to the tank bottom. Solids are collected as a sludge from the bottom of the tank and clean condensate is obtained from the top. [**40**,**44**]. The sludge from the lamella clarifier can for example be fed to boiler for burning or dried with belt filter press and stored [**38**]. Typically flocculation chemicals are added prior the clarifier to further enhance the separation. Lamella clarifier can be ran in pair with sand filter, so that if condensate has high amounts of suspendend solids, the lamella clarifier is used prior the sand filter [**35**].

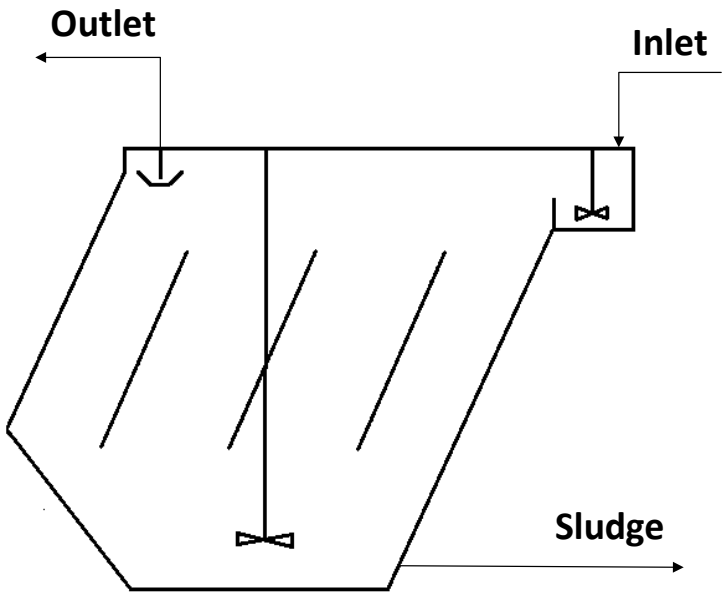


*Figure 4. Principle of lamella clarifier [**35**].*

As mentioned, to separate heavy metals and salts, ion exchangers are used. In an ion exchanger column, condensate flows through a charged bed, which replace ionic compounds such as Hg^{2+}, Mg^{2+}, Na^{+} and Cl^{-} with either H^{+} or OH^{-} [**39**]. The bed consists of chelating functional groups of different kinds, which are specific to certain components in condensate and are attached to porous base-material backbone. These functional groups can either be positively (cations) or negatively (anions) charged, which are being consumed in the process, so the bed must frequently be regenerated or changed. Regeneraration of cations are done with acid and anions with base additive rinsing [**45**]. Because of this changing or regeneration, ion exchangers are operated in pairs to ensure continuous cleaning [**39**]. Incoming BAT-AELs for heavy metals are expected to be strict, so focus for condensate treatment will be in these components. Chelating groups that are specific for these are for example iminodiethanoic (TP 207) and thiourea (TP 214) [**45**,**46**].

Temperature and pH of the condensate are also typically adjusted. Temperature can be controlled by directing condensate to a heat exchanger, where it is cooled by natural waters. Cooling can also be done with air in a cooling tower. pH is controlled by adding chemical additive such as NaOH or sulphuric acid to the stream [**28**,**47**].

Often the regulations for the water discharge are reached using the previously mentioned technologies, but sometimes, if the regulations are strict or it is desired to produce boiler water from the condensate, membrane filtration techniques are used [**28**]. The membrane filtration processes are classified based on the pore size of the membrane applied. Microfiltration (MF) uses membranes with the largest pore size ranging from 0.1 to 1 µm, ultrafiltration (UF) with 0.01–0.1 µm, nanofiltration (NF) 0.001–0.01 µm, and reverse osmosis (RO) with pore size of 0.0001–0.001 µm. When the pore size decreases, also the flux through the membrane is decreased. Pore size has also an effect on the pressure drop through the membrane, which is higher when the pores are smaller [**40**].

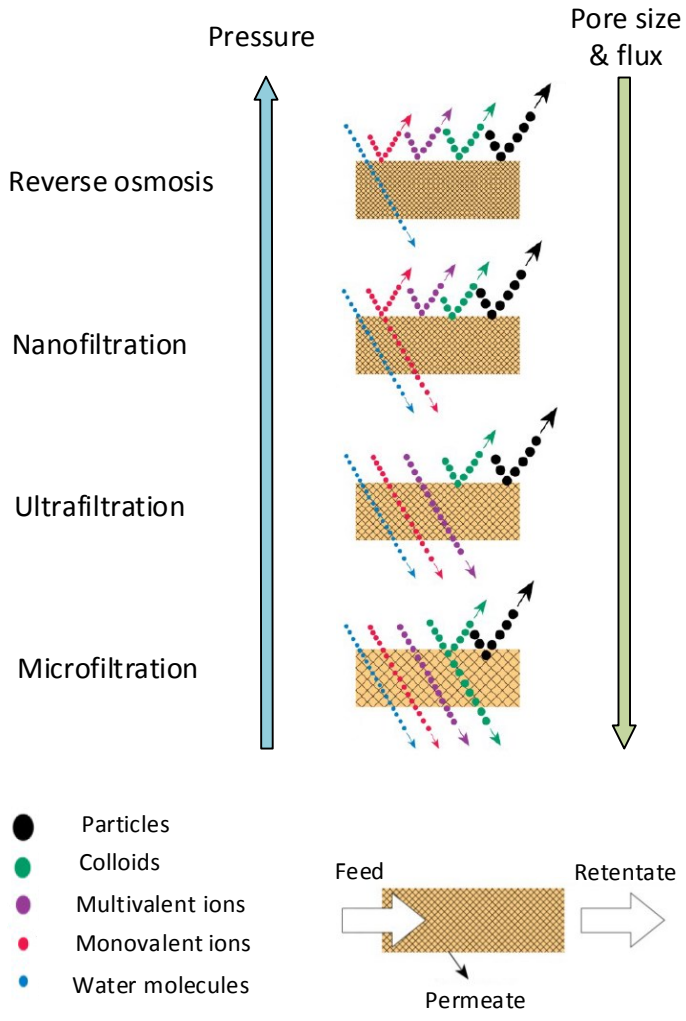


*Figure 5. Components retained in different membrane filteration processes [**28**].*

As can be seen from figure 5 the membrane filtration technologies can be used for separating many kinds of impurities. MF can be used for separating particles as well as some of the large colloids present in the condensate. UF membranes retain all the colloids as well as the larger particles, but lack the ability to separate ions. Multivalent ions (Ca^{2+}, Mg^{2+}) can be separated from monovalent ions (Na^{+}, Cl^{-}) using NF. RO is the only one able to separate water molecules from even the tiniest monovalent ions. The membranes are arranged into modules, which are designed to maximize the membrane surface area in a given floor space and to reduce membrane fouling. It is also typical to combine different membrane filtration techniques into a series. For example, the fouling of RO membranes can be reduced by using UF as a prefiltration [**28**].

Depending on the quality of condensate formed in FGC and requirements the most optimized technology for treatment is selected. The selection of the optimal purification techniques and design of the treatment process typically requires testing in laboratory and pilot scale [**45**]. However, some general guidelines can be used to choose the suitable techniques based on the properties of the condensate. For example, if condensate has low amounts of solids, simple bag filter may be enough. If solids content is high, lamella clarifier can be used. The reject produced in this treatment can be fed to the boiler furnace or dried with a belt filter press. If the condensate does not meet the drain requirements after the clarifier, a sand filter can be added as a final treatment step. If heavy metals are still a problem, ion exchange can be used. [**35**,**40**]. As mentioned before a further treatment using a combination of UF and RO can be used to produce water that meets the boiler water quality standards.

2.4. Wet stack design

After FGC, the clean flue gas is in its saturation point. Outside temperature is often lower than the flue gas dew point, which causes condensation on the stack inside surface. This condensation can be reduced by the use of a proper insulation in the stack. Flue gas may also contain droplets, which deposit to the stack inside surface. Therefore droplet separation is used before the stack to prevent liquid carryover to the stack. Newertheless the condensation and droplet deposition cannot be fully prevented, and thus the stack needs a proper drainage and liquid collection system. Liquid from the drainage can be directed back to FGC. Flue gas contains also acidic components, which may condensate. This condensation may lead to corrosion of the stack components, if material selection is not stressed. If FGC bypass is used, the materials used in the stack, should also be able to handle high temperatures [**5**].

Buoyancy depends on the flue gas temperature. Flue gas temperature decreases in FGC, which causes emissions to spread closer, unless the stack height is increased. However, the emission levels after FGC are much lower, which compensates ground level emission concentrations. Therefore, it is seldom necessary to increase stack height. Emission dispersion can also be compensated using a higher flue gas exit velocity. However, this velocity cannot be endlessly increased due to liquid entrainment into the flue gas. This entrainment occurs when the force from the flue gas velocity exceeds that of gravity and liquid surface tension in the stack inside surfaces. The liquid entrainment phenomenon is affected not only by the velocity, but also by the stack material [**5**]. A typical wet stack design velocity is 15 m/s [**4**]. In some cases, entrainment problems may even cause liquid to shower nearby the stack [**5**].

Flue gas exit velocity affects also a phenomenon called plume downwash effect. In the plume downwash effect, the flue gas plume may partially mix with vortex patterns that are formed on the downwind side of the stack. This effect can be prevented by ensuring that the flue gas momentum is high enough compared to across-wind momentum at the top of the stack, which will try to deflect the plume from its vertical

path. Momentum can be increased, for example, by installing a choke to the top of the stack. Plume downwash effect also increases ice formation in the winter. Ice formation is a problem in parts which are in contact with the moisture of the flue gas or rain. Icing can be prevented with lack of insulation in the stack top parts, but also by heating up the stack hood with electricity [**5**]

2.4.1. Gaussian plume model

In FGC flue gas is cooled down, which affects the plume rise and, consequently, to emission dispersion. Plume modeling is used for estimating the plume movement and the emission concentration dispersion. Gaussian plume model is one of the earliest models for the purpose and it is still widely used. The model assumes plume emissions to disperse according to normal distribution within the plume. Other assumptions made in the modeling are [**48**,**49**]:

1) Dispersion is neglible in the downwind (x) direction
2) Meteorological conditions (wind speed, direction, temperature, atmospheric stability class) are homogeneous in the area of calculation
3) There is no horizontal or vertical wind sheer
4) Plume has no plume history
5) The pollutants do not react
6) The plume is reflected at the surface with no deposition or reaction with the surface
7) The dispersion in the crosswind (y direction) and vertical (z direction) take the form of Gaussian distributions about the plume centerline
8) There are no tall buildings or shapes in the area

When these assumptions hold, ground level concentrations with Gaussian plume model at point (x, y) can be presented as [**49**]:

$$C(x,y,0,H) = \frac{Q}{\pi U \sigma_y \sigma_z}\, e^{\left(\frac{y^2}{2\sigma_y^2}\right)}\, e^{\left(\frac{H^2}{2\sigma_z^2}\right)} \quad (1)$$

where

C(x,y,0,H) = ground level concentration according to Gaussian plume model (mg/m^3)

Q = source emission rate (mg/s)

U = wind speed at stack height (m/s)

σ_y, σ_z= standard deviations of concentration distributions in horizontal and vertical directions respectively (m)

H = effective stack height, which is the sum of stack height, plume rise and height above the sea level (m)

x = distance downwind from the stack (m)

y = distance crosswind from the plume centerline (m)

Standard deviations of the concentration distributions in crosswind and vertical directions can be estimated from the specific atmosphere stability class based correlations. If neutral conditions (stability class D) are assumed, correlations can be presented as [**49**]:

$$\sigma_y = 0.122 * x^{0.916} \quad (2)$$

for distance downwind from stack below 10 km.

$$\sigma_z = 0.2591 * x^{0.6869} \quad (3)$$

for distance crosswind from plume centerline between 0.5 – 5 km.

Wind speed is proportional to height and it can be adjusted with following equation [**49**]:

$$U = U_0 * \left(\frac{Z}{Z_0}\right)^p \quad (4)$$

where

U_0 = wind speed at anemometer height (m/s)

Z_0 = anometer height (ground level, above the sea level) (m)

Z = desired height (stack height) (m)

P = function of stability class (0.3 for D)

Plume rise is affecting to effective stack height aswell, which can be presented for buoyancy dominated plume rise in neutral atmospheric conditions as [**49**]:

$$\Delta h = 1.6F^{\frac{1}{3}} * 3.5x^{*\frac{2}{3}} * U^{-1} \quad (5)$$

where

Δh = plume rise

x* = distance to determine maximum plume rise

and

$$F = \frac{gVR^2(T-T_A)}{T} \quad (6)$$

where

T = source temperature (K)

T_A = ambient temperature (K)

V = stack exit velocity (m/s)

R = stack radius (m)

g = acceleration due to gravity (9.81 m/s^2)

The maximum plume rise is obtained when x > 3.5x*. x^* used is defined as:

$$x^* = 14F^{\frac{5}{8}} \quad (7)$$

when F < 55

$$x^* = 34F^{\frac{2}{5}} \quad (8)$$

when F > 55

Sometimes the flue gas is at a low temperature and has high exit velocity from the stack. In such case, momentum can dominate plume rise. Momentum dominated plume rise can be calculated using equation 9 [**49**]:

$$\Delta h = \frac{3VD}{U} \quad (9)$$

where

D = stack inside diameter (m)

Next, an example of calculating the ground level concentration for a specific emission using the Gaussian plume model. A power plant emits Q = 7000 mg/s of SO_2 to the atmosphere. Flue gas temperature is T = 150℃ = 423.15 K, and the exit velocity from stack is V = 20 m/s. Stack inside diameter is 2 meters and there is no choke installed. Stack height is 80 meters. Outside temperature is T_A = 10℃ = 283.15 K and wind speed is U_0 = 6 m/s at anometer height Z_0 = 5m. Atmospheric stability class is therefore assumed to be class D, i.e., neutral. The ground level concentration of SO_2 at the distance of 5 kilometers downwind and 0.5 kilometer crosswind (5000m, 500m) from the stack is determined.

The determination of the ground level concentration begins by calculating wind speed at stack height using equation 4:

$$U = 6\frac{m}{s} * \left(\frac{80}{5}\right)^{0.3} = 13.78\frac{m}{s}$$

This wind speed is used in both buoyancy and momentum plume rise calculation and then dominating factor is selected. Plume rise for buoyancy is calculated, but first F factor is determined using equation 6:

$$F = \frac{9.81\frac{m}{s^2} * 20\frac{m}{s} * (1m)^2(423.15K - 283.15K)}{423.15K} = 64.94$$

Because F > 55, equation 8 is used to determine: what is the distance from the stack for maximum plume rise:

$$x^* = 34 * 64.94^{\frac{2}{5}} = 180.50m$$

The buoyancy driven plume rise (calculated from equation 5) is used to determine the plume rise:

$$\Delta h = 1.6 * 64.94^{\frac{1}{3}} * 3.5 * (180.50m)^{\frac{2}{3}} * \left(13.78\frac{m}{s}\right)^{-1} = 52.15m$$

The momentum plume rise is calculated from equation 9:

$$\Delta h = \frac{3 * 20\frac{m}{s} * 2m}{13.78\frac{m}{s}} = 8.7m$$

Buyoancy is determined to be dominating factor, because 52.15m > 8.7m. Now the effective stack height can be calculated by adding the buoyancy dominated plume rise to the stack height:

$$H = 80m + 52.15m = 132.15m$$

Next, horizontal and vertical standard deviations for SO_2 emission is calculated. For the horizontal one, equation 2 is used:

$$\sigma_y = 0.122 * 5000^{0.916} = 298.27m$$

and for the vertical standard deviation, equation 3 is used:

$$\sigma_z = 0.2591 * 5000^{0.6869} = 90.01m$$

Now, the ground level concentration in target point can be calculated from equation 1:

$$C(5000m, 500m, 0{,}145.1m) =$$

$$= \frac{7000\frac{mg}{s}}{\pi * 13.78\frac{m}{s} * 298.27m * 90.01m} * e^{(\frac{(500m)^2}{2*(298.27m)^2})} * e^{(\frac{(132.15m)^2}{2*(90.01m)^2})}$$

$$= 5.03 * 10^{-4}\frac{mg}{m^3}$$

3. FLUE GAS HEAT RECOVERY

Heat recovery is important, because it can make the FGC profitable. Heat recovery can be defined as recovering heat from a heat source to a form in which it can be further utilized. This action increases the overall efficiency of the plant, which is also considered in the latest version BAT-AEELs. [**50**]. Heat in the flue gas can be recovered in two forms, as sensible heat and as latent heat. In the recovery of sensible heat, heat is transferred through a temperature difference between a hot and a cold side. This form of heat transfer is dependent on heat capacities and the mass or molar flows used. Sensible heat is defined as [**51**,**52**]:

$$P = c_p * m * dT \quad (10)$$

where,

m = mass flow (kg/s)

c_p = heat capacity of the flow (kJ/kgK)

dT = temperature difference between cold and hot side (℃ or K)

P = Heat transfer output (kW)

Heat transfer through latent heat utilizes the energy trapped in a form of phase transition. For example, when water vapor condensates onto a cold surface that is colder than the vapor dew point, the energy trapped in this phase transition is released. Dew point is determined as the point when relative humidity is 100% and it is a function of saturated steam pressure and partial pressure of the water vapor in the gas. When the partial pressure of the water vapor reach the saturated steam pressure, condensation occurs. Since the shape of the saturated steam pressure curve is steep, the moisture content of the gas decreases significantly with the temperature.

This is why the heat transfer can be very efficient, if high temperature difference between the cold surface and the dew point pertain [**53**].

Latent heat can be defined with equation 11 [**51**,**52**].

$$P = m * l \tag{11}$$

$$\mathrm{l} = \text{heat of phase transition (kJ/kg)}$$

Examples of these two heat transfer types can be given by heating up DH return water (T_{return} = 50 °C; mass flow m_{dh} = 263 kg/s) with dry or wet flue gas ($T_{fg,in}$ = 149 °C; m_{fg} = 74 kg/s).

First we calculate how much DH return water can be heated with dry flue gas. We assume that minimum temperature approach between the hot and cold side is 2°C, so flue gas outlet temperature is $T_{fg,out}$ = 52°C in a counter current heat exchanger (figure 6). The heat capacity can be assumed to be the same in the investigated temperature range $c_{p,w}$ = 4.19 kJ/kgK for the DH return water and $c_{p,a}$ = 1,061kJ/kgK for the flue gas.

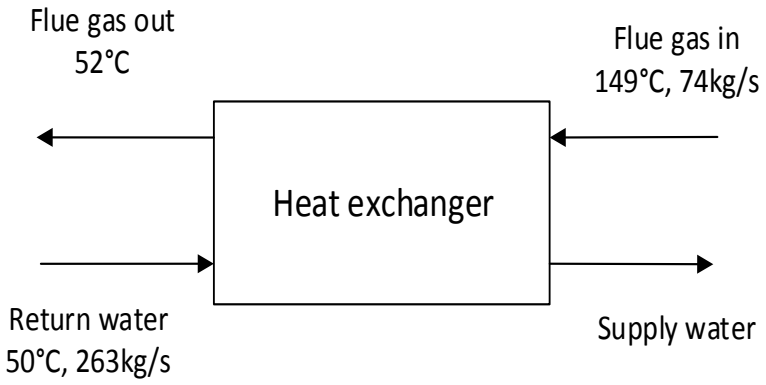


Figure 6. Example of a counter current heat exchanger.

The energy balance can be written based on equation 10:

$$P = c_{p,w} * m_{dh} * \left(T_{supply} - T_{return}\right) = c_{p,a} * m_{fg} * \left(T_{fg,in} - T_{fg,out}\right)$$

$$T_{supply} = \frac{c_{p,a} * m_{fg} * \left(T_{fg,in} - T_{fg,out}\right) + c_{p,w} * m_{dh} * T_{return}}{c_{p,w} * m_{dh}}$$

$$= \frac{1.061\,\frac{kJ}{kgK} * 74\,\frac{kg}{s} * (149℃ - 52℃) + 4.19\,\frac{kJ}{kg\,K} * 263\,\frac{kg}{s} * 50℃}{4.19\,\frac{kJ}{kg\,K} * 263\,\frac{kg}{s}}$$

$$T_{supply} = 56.9℃$$

To compare this result obtained for dry flue gas with the case in which wet flue gas with x_1 = 0.15 kg/kg_{dry} of absolute moisture in the same temperature used, we change the heat exchanger into a tube condenser. Dry flue gas mass flow is m_{dg} = 64.35 kg/s, and the initial moisture content is $m_{mo,1}$ = 9.65 kg/s. Initial dew point temperature read from Mollier diagram for the flue gas is $T_{dew\ point,1}$ = 59.5℃ [**54**]. However, in tube condenser, the flue gas is first in contact with water before heat transfer surface. This contact with water increases the moisture content of flue gas, as the water is evaporated with sensible heat. Consequently the dew point temperature increases, making the calculation iterative. Moisture content has also an effect on heat capacity, but to simplify the calculation, it is assumed to stay constant. To calculate the sensible heat of flue gas transferred, we use equations 10 and 11, assuming the circulating flow to be in the dew point temperature and the heat of phase transition to be around l = 2360 kJ/kg.

$$P = c_{p,a} * m_{fg} * \left(T_{fg,in} - T_{dewpoint,1}\right) = l * m_{mo,i}$$

$$m_{mo,i} = \frac{c_{p,a} * m_{fg} * \left(T_{fg,in} - T_{dewpoint,1}\right)}{l}$$

$$m_{mo,i} = \frac{1.061\frac{kJ}{kgK} * 74\frac{kg}{s} * (149℃ - 59.5℃)}{2360\ kJ/kg} = 2.98\frac{kg}{s}$$

This is added to the initial moisture of flue gas: $m_{mo,1}$ = 9.65 kg/s

$$m_{mo,2} = m_{mo,1} + m_{mo,i} \quad (12)$$

$$m_{mo,2} = 9.65\frac{kg}{s} + 2.98\frac{kg}{s} = 12.63\frac{kg}{s}$$

Now to convert this to absolute moisture:

$$x_2 = \frac{12.63\frac{kg}{s}}{64.35\frac{kg}{s}} = 0.196\frac{kg}{kg_{dry}}$$

Now the dewpoint read from the Mollier diagram is $T_{dewpoint,2}$ = 64℃. The difference between the initial and the new dewpoints is 5.5℃. When the dew point is read directly from the Mollier, some inaccuracy pertains, and further iteration would not change the dew point much in this case (the actual dewpoint is around 63.8℃).

When cooling down the flue gas in the condenser, relative humidity stays near 100% and after cooling the flue gas temperature is assumed to be 2 degrees above the DH return water temperature of 50℃. For flue gas at 52℃, the absolute moisture read from the Mollier diagram is around 0.098 kg/kg_{dry}. Thus, the moisture content decreases:

$$x_{dec} = 0.196\frac{kg}{kg_{dry}} - 0.098\ \frac{kg}{kg_{dry}} = 0.098\frac{kg}{kg_{dry}}$$

The rate of water condensation is:

$$m_{cond} = 0.098 \frac{kg}{kg_{dry}} * 64.35 \frac{kg}{s} = 6.3 \frac{kg}{s}$$

The supply water temperature when the flue gas is cooled can be calculated using equations 10 and 11:

$$P = c_{p,w} * m_{dh} * \left(T_{supply} - T_{return}\right)$$

$$= c_{p,a} * m_{fg} * \left(T_{fg,in} - T_{fg,out}\right) + l * m_{cond}$$

$$T_{supply} = \frac{c_{p,a} * m_{fg} * \left(T_{fg,in} - T_{fg,out}\right) + m_{cond} * l + c_{p,w} * m_{dh} * T_{return}}{c_{p,w} * m_{dh}}$$

$$= \frac{1.061 \frac{kJ}{kgK} * 74 \frac{kg}{s} * (149℃ - 52℃) + 6.3 \frac{kg}{s} * 2360 \frac{kJ}{kgK} 4.19 \frac{kJ}{kg\ K} * 263 \frac{kg}{s} * 50℃}{4.19 \frac{kJ}{kg\ K} * 263 \frac{kg}{s}}$$

$$T_{supply} = 70.4℃$$

Dew point limits the heat recovery, so actually DH return water is warmed to dew point minus the temperature approach, 62℃. Rest of the heat can be recovered if DH flow is increased. As can be seen, the potential of latent heat is substantially higher compared to sensible heat. However, the most significant attribute for the heat recovery is to get the flue gas out of the system as cold as possible, because the temperature affects both, sensible and latent heat transfer.

3.1. Heat revovery technologies

There are roughly four different methods related to FGC for flue gas heat recovery. The first method is heat transfer trough sensible heat, which considers only the temperature difference between cold and hot side without any phase shifts (Method 1) [**50**]. This method can be demonstrated by adding a heat exchanger before the

scrubber (figure 7). This type of heat recovery is usually used for plants operating with low moisture content fuels such as coal. Sensible heat can be utilized to heat up combustion air or turbine condensate [**50**,**55**].

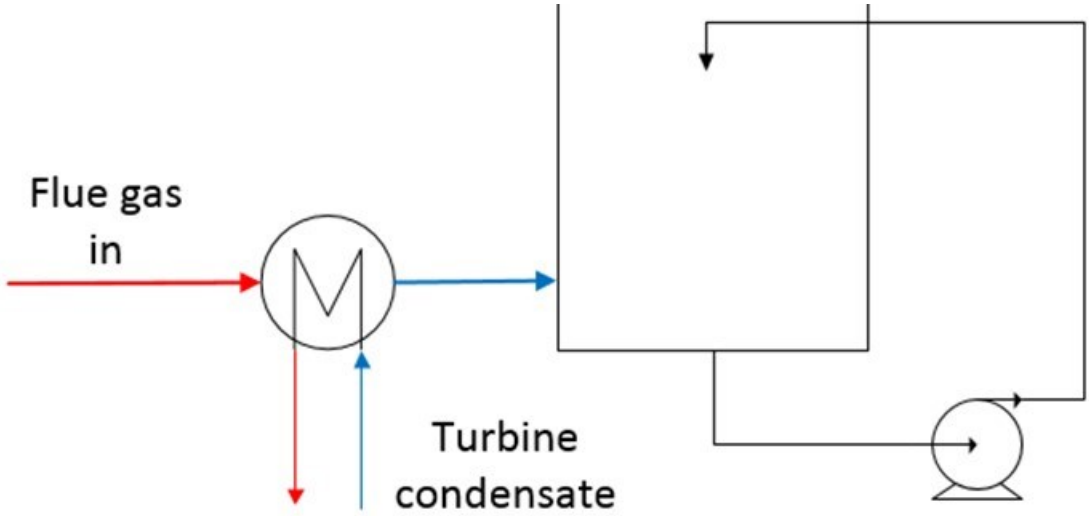


*Figure 7. Example of method 1. Heat exchanger before scrubber [**50**,**55**].*

Second method for heat recovery utilizes the latent heat of flue gas by condensing moisture (method 2). This method can be done either in a tube condenser (figure 8) or in a condensing scrubber. Moisture content of flue gas is first increased to the saturation point and then condensed to condenser surface or to water circulation. Sensible heat is also transferred at the same time [**28**].

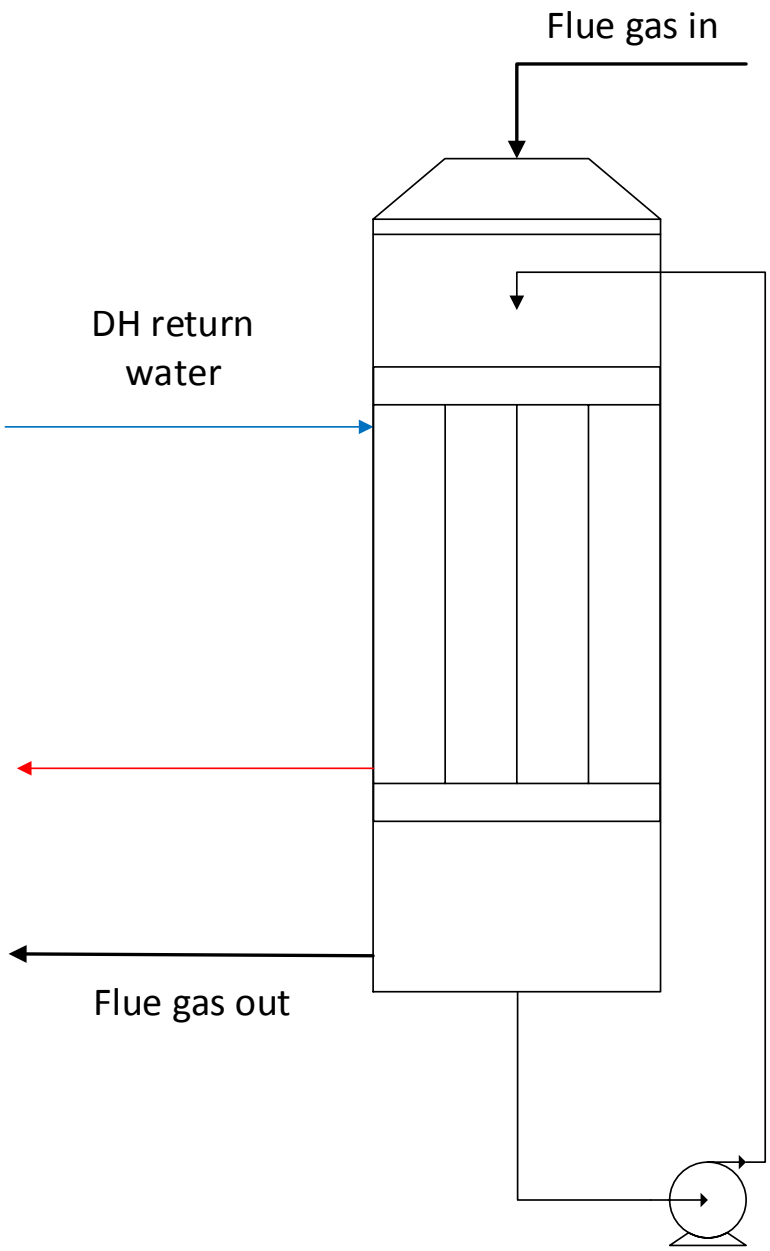


*Figure 8. Example of method 2. Plain condensation in tube condenser [**1**].*

Third method is condensation enhanced with a heat pump (Method 3). This method is used when cold enough DH return water is not available. Heat pump decreases the temperature of the DH return water, which increase heat recovery by further condensing the flue gas humidity [**56**]. It can be attached directly to the circulating

steam (figure 9) or to DH network (figure 10). The heat pump itself can be operated with electricity or with steam [**35**,**56**].

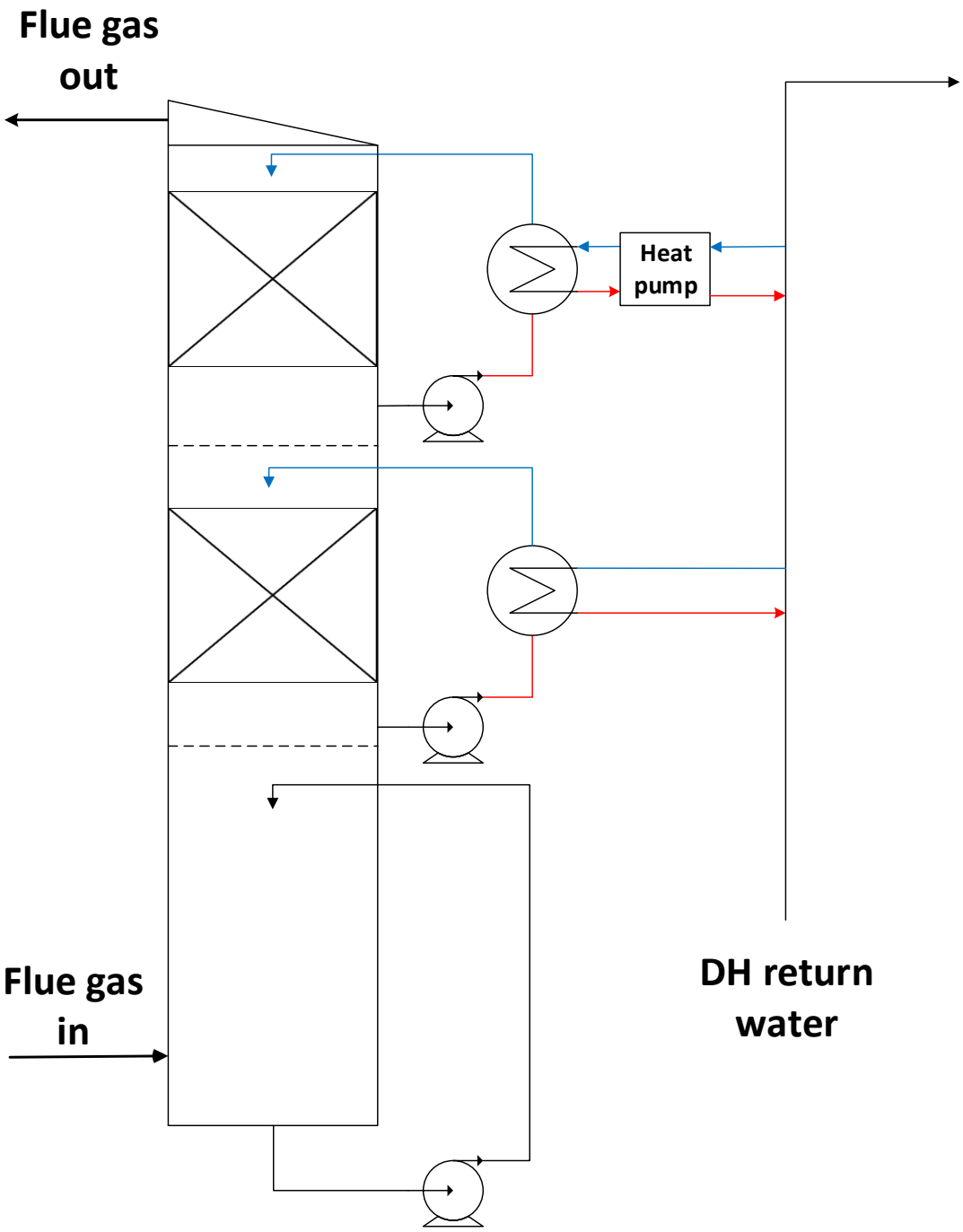


*Figure 9. Example of method 3. Condensation with heat pump [**57**].*

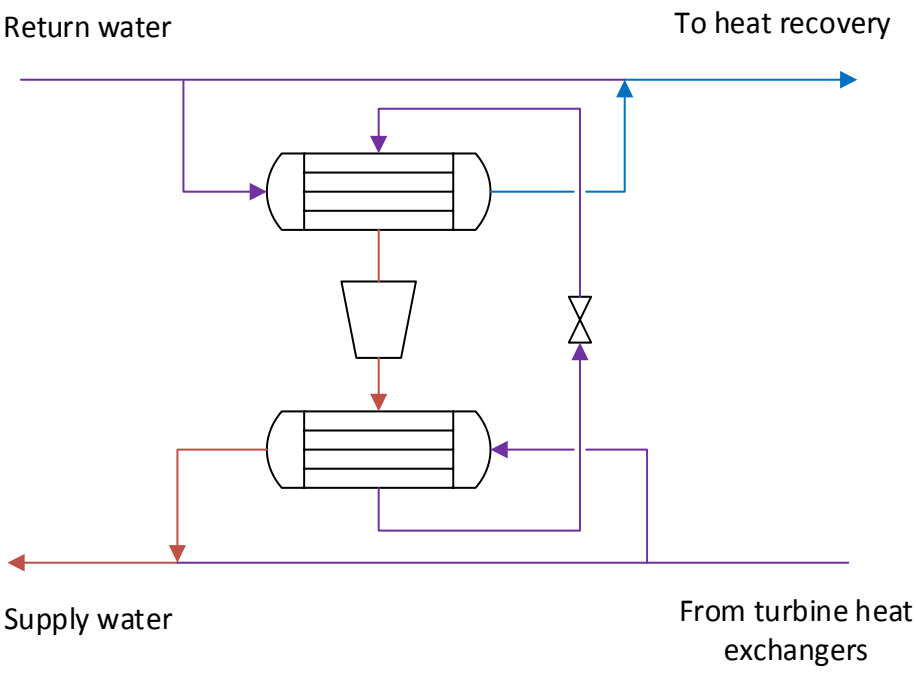


*Figure 10. Heat pump integrated to district heating network [**35**,**58**].*

Fourth method is to add a combustion air humidifier (CAH), which increases the moisture content of combustion air and flue gas (Method 4). CAH is a packed bed column, like a scrubber, where air is fed to the bottom section and humidified with water sprayed from above. Packaging is used to enhance heat transfer. Humidified air is taken from the top and is fed to the boiler, where it is turned into flue gas. When CAH is used, flue gas has higher moisture content and the dew point is increased. This means that the flue gas condensing starts at a higher temperature and more heat can be recovered in FGC. Flue gas outlet temperature is also decreased, because circulating water is cooled with combustion air. CAH could be connected to the water circulation of FGC as in figure 11, but usually only part of the heat recovery stage waters are directed to CAH [**1**,**59**].

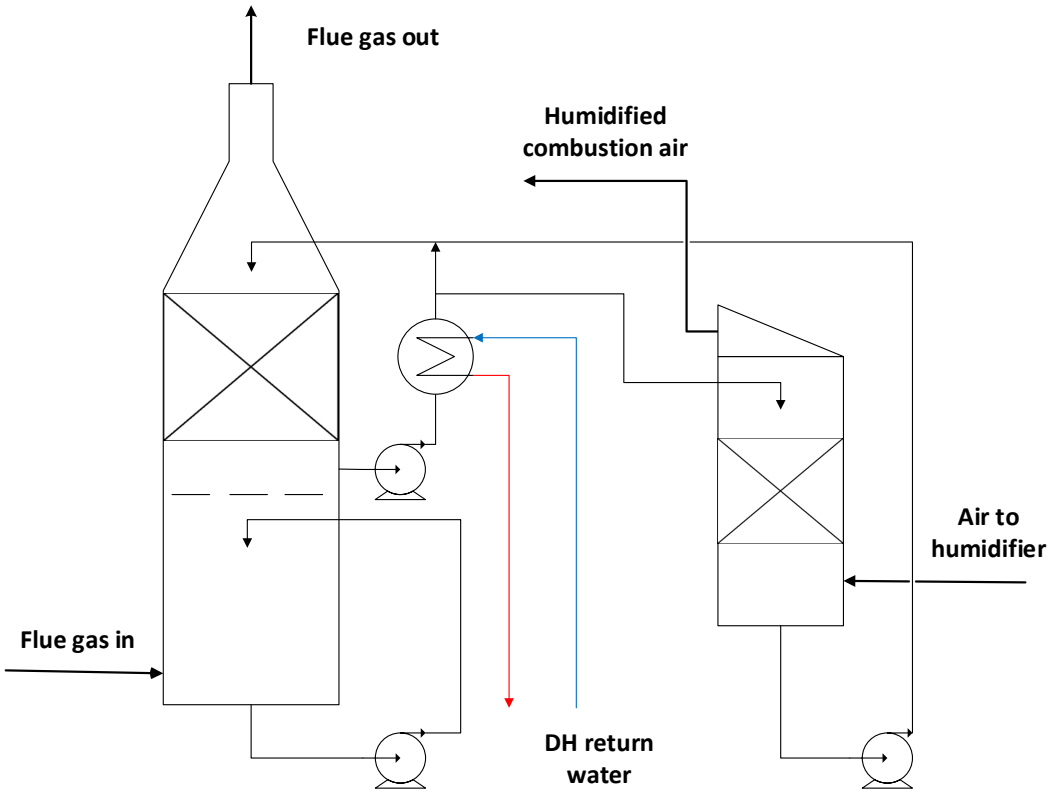


*Figure 11. Example of method 4. CAH attached to scrubber, simplified from sources [**1**,**59**].*

Similar to method 3 (use of a heat pump), the CAH method is beneficial when DH return temperature is high. As seen in figure 12, heat recovery is better with CAH than without it when the temperature of DH return water temperature is the same.

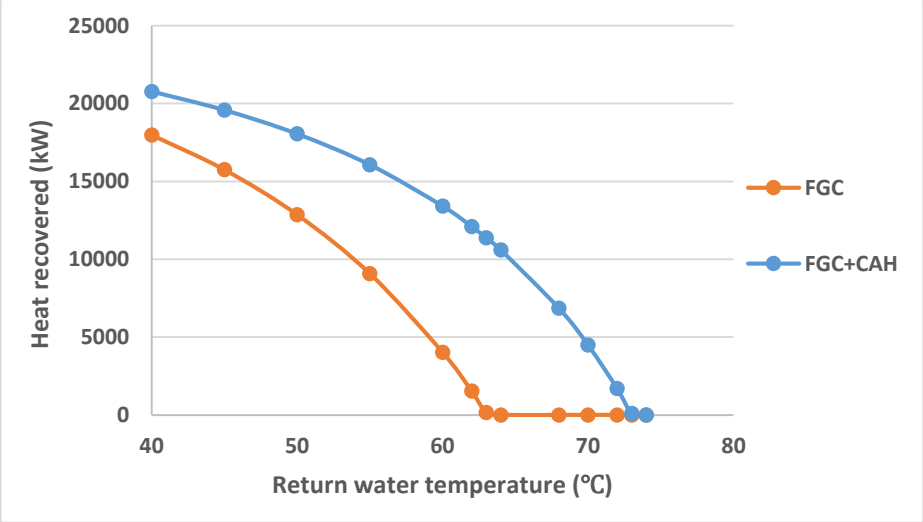


Figure 12. Effect of combustion air humidification to heat recovery (calculated).

3.2. Heat recovery potentials

Potentials of the previously mentioned heat recovery methods are calculated and evaluated in this section. To increase the accuracy of potential calculations, the flue gas properties are also calculated. The conditions used in calculations are based on yearly averages.

3.2.1. Flue gas properties

In section 3, heat recovery example calculations were done with the assumption that the flue gas composition is close that of air. Also heat capacity was assumed to be the same for dry and moisturized air. However, flue gas dry and wet heat capacities as well as molar masses are important properties for precise calculations. Composition of flue gas is shown in table 8 and the properties of the main components are listed in table 9.

*Table 8. Main components of flue gas (HK 6 stack) [**60**].*

Component	Volume fraction	Volume fraction (dry)
CO2	0.104	0.132
O2	0.055	0.069
H2O	0.210	
N2	0.631	0.799

*Table 9. Component properties [**54**,**61**].*

Component	Molar mass (g/mol)	Heat capacity (J/kgK)
CO2	44	844
O2	32	918
H2O	18	1850
N2	28	1040

If flue gas is assumed to behave close to ideal gas in near atmospheric pressure, ideal gas law can be used. It states that the volume fractions can be directly converted to molar fractions. The average molar mass of a mixture can be calculated as follows [**53**]*:*

$$M = \sum_1^i x_i \, M_i \qquad (13)$$

where

M = molar mass of mixture (g/mol)

x_i = molar fraction of component I

M_i = molar mass of component I (g/mol)

To calculate molar mass of flue gas, component molar masses as well as the information about the flue gas composition are substituted into equation 13.

$$M_{dg} = 0.132 * 44\frac{g}{mol} + 0.069 * 32\frac{g}{mol} + 0.799 * 28\frac{g}{mol}$$

$$M_{dg} = 30.4\frac{g}{mol}$$

And for wet flue gas:

$$M_{wg} = 0.104 * 44\frac{g}{mol} + 0.055 * 32\frac{g}{mol} + 0.210 * 18\frac{g}{mol} + 0.631 * 28\frac{g}{mol}$$

$$M_{wg} = 27.6\frac{g}{mol}$$

Another important property is the heat capacity of the flue gas. It can be calculated either in mass or molar basis. To calculate in mass basis, weight fractions of the components are needed and, those can be calculated from molar masses and molar fractions using equation 14:

$$w_i = x_i \frac{M_i}{M} \quad (14)$$

where

w_i = weight fraction of component i

The weight fractions of the components in dry basis are:

$$w_{CO2} = x_{co2}\frac{M_{co2}}{M_{dg}} = \ 0.132 * \frac{44\frac{g}{mol}}{30{,}4\frac{g}{mol}} = 0.191$$

$$w_{O2} = 0.073$$

$$w_{N2} = 0.736$$

and in wet basis:

$$w_{CO2} = 0.104 * \frac{44\frac{g}{mol}}{27.6\frac{g}{mol}} = 0.165$$

$$w_{O2} = 0.063$$

$$w_{H2O} = 0.136$$

$$w_{N2} = 0.636$$

Heat capacity of mixture can be calculated as follows:

$$c_{p,m} = \sum_1^i w_i \, c_{p,i} \quad (15)$$

where

$c_{p,m}$ = heat capacity of mixture (kJ/kgK)

$c_{p,i}$ = heat capacity of component I (kJ/kgK)

Therefore, the heat capacity of the dry flue gas:

$$c_{p,dg} = 0.191 * 844\frac{J}{kgK} + 0.073 * 918\frac{J}{kgK} + 0.736 * 1040\frac{J}{kgK}$$

$$c_{p,dg} = 1005.7\frac{J}{kgK} = 1.0057\frac{kJ}{kgK}$$

and for wet flue gas:

$$c_{p,wg} = 0.165 * 844\frac{J}{kgK} + 0.063 * 918\frac{J}{kgK} + 0.136 * 1850\frac{J}{kgK} +$$

$$0.636 * 1040\frac{J}{kgK}$$

$$c_{p,wg} = 1075\frac{J}{kgK} = 1.075\frac{kJ}{kgK}$$

Absolute moisture can be calculated from the wet gas weight fractions.

$$x = \frac{w_{H2O}}{w_{O2}+w_{N2}+w_{CO2}} \quad (16)$$

$$x = \frac{0.136}{0.063+0.636+0.165} = 0.1575\frac{kg}{kg_{dry}}$$

3.2.2. Method 1 (Sensible heat)

Acid dew point limits possibilities for the use of method 1, because of the challenges it sets to the material selection. Two examples of the use of method 1 are given here. In the first example, the flue gas temperature is allowed to decrease below the dew point.

Sensible heat recovered can be calculated by using equation 10. If flue gas mass flow is 50.9 kg/s and Cp,wg = 1.075kJ/kgK and the gas is cooled to 120℃, which is above the acid dew point, heat recovered can be calculated using equation 10:

$$P = c_p * m * dT = 1.075\frac{kJ}{kgK} * 50.9\frac{kg}{s} * (149℃ - 120℃) = 1586\ kW$$

When the flue gas is cooled down to a temperature of 80℃, which is below the acid dew point and well above the vapor dew point, the heat recovered increases:

$$P = 1.075\frac{kJ}{kgK} * 50.9\frac{kg}{s} * (149℃ - 80℃) = 3774\ kW$$

Again, if cooled below the acid dew point, material selection will be challenging.

3.2.3. Method 2 (Plain condensation)

In the reference CHP plant, the yearly average of the DH return water temperature is 50.6℃. With the 2℃ temperature approach, this means that the water circulation can be cooled down to 52.6℃. In FGC, the amount of water circulated is so large that the flue gas temperature in the end of heat recovery stage is the same as the temperature of the cooled circulating water, which is sprayed from the top. To calculate the heat recovered with method 2, similar heat recovery calculations as presented in section 3 example are done, but now the heat recovered is determined as the enthalpy difference between the FGC inlet and outlet. The absolute moisture content of the flue gas is, as previously calculated, x = 0.1575 kg/$kg_{dry.}$ To calculate the total enthalpy, temperature reference point is defined asT_{ref} = 0℃ (water evaporates at this reference temperature). Total enthalpy can be calculated from equation 17 [51,53]:

$$H,k = H,i + x * H,h \quad (17)$$

where

H,i = enthalpy of sensible heat (kJ/kg)

H,h = enthalpy of latent heat (kJ/kg)

H,k = total enthalpy (kJ/kg)

Equation 17 expresses the sensible and the latent heat trapped in the flue gas. Sensible heat can be determined by equation 18 [**53**]:

$$H,i = Cp,dg * (T - T_{ref}) \quad (18)$$

where

T_{ref} = reference temperature (℃ or K)

Latent heat can be expressed with equation [**53**]:

$$H,h = l + c_{p,v} * T \quad (19)$$

where

$C_{p,v}$ = heat capacity of water vapor (kJ/kgK)

Latent heat at the reference temperature is l = 2501.4 kJ/kg. Heat capacity value for dry flue gas is Cp,dg = 1.0057 kJ/kg. Change in heat capacity of flue gas is minor in the investigated temperature range, so it is assumed to stay constant. However, for vapor the temperature dependence of heat capacity has some significance, and average heat capacity value is, therefore, used. Heat capacity for 75℃ vapor is Cp,v = 1.91 kJ/kgK. Enthalpy of flue gas can be calculated by combining equations 18 and 19 with equation 17:

$$H,k = H,i + x * H,h = Cp,dg * (T - Tref) + x * (l + Cp,v * (T - Tref)) \quad (20)$$

$$H,k1 = 1.0057 \frac{kJ}{kg} (149℃ - 0℃) + 0.1575 \frac{kg}{kg_{dry}} * (2501.4 \frac{kJ}{kg} + 1.91 \frac{kJ}{kg} * (149℃ - 0℃))$$

$$H,k1 = 588.53\ kJ/kg$$

It is known that the temperature at the flue gas outlet is 52.6℃, and that the flue gas is at its saturation point. As mentioned dew point is determined as the point when relative humidity is 100%. Relative humidity can be calculated using the following equation [**51**,**53**]:

$$\partial = \frac{p_h}{p_{h'}} * 100\% \quad (21)$$

where

∂ = relative humidity (%)

p_h = the partial pressure of water in the flue gas (Pa)

p_h' = the saturated steam pressure in the flue gas (Pa)

To calculate the partial pressure of water in the flue gas, ideal gas law is used. Flue gas consists of dry gas and water vapor. For dry gas, partial density is [**53**]:

$$\rho_g = \frac{p_g M_g}{RT} \tag{22}$$

Correspondingly for water vapor:

$$\rho_h = \frac{p_h M_h}{RT} \tag{23}$$

where

ρ_g = partial density of dry gas (kg/m^3)

ρ_h = partial density of water (kg/m^3)

M_g = molar mass of dry gas (g/mol)

M_h = molar mass of water vapor (g/mol)

R = gas constant (8.314 J/Kmol)

T = Temperature of the system (K)

Total density is the sum of partial densities [**53**]:

$$\rho = \rho_g + \rho_h \tag{24}$$

and total pressure is the sum of partial pressures [**53**]:

$$P_0 = p_g + p_h \quad (25)$$

where

P_0 = total pressure of the system (Pa)

p_g = partial pressure of gas (Pa)

p_h = partial pressure of water (Pa)

Absolute moisture can be defined as a ratio of the partial densities of water and dry gas [**53**].

$$x = \frac{\rho_g}{\rho_h} \quad (26)$$

According to equation 22, 23 and 26:

$$x = \frac{M_h\, p_h}{M_g\, p_g} \quad (27)$$

As previously calculated, the molar mass of dry flue gas is M_{dg} = 30.4 g/mol, and the molar mass of water is M_h = 18g/mol. Substituting these values to equation 27 and 25:

$$x = 0.5923 * \frac{p_h}{p_g} = 0.5923 * \frac{p_h}{P_0 - p_h} \quad (28)$$

Finally, the partial pressure of water vapor can be solved:

$$p_h = \frac{x}{0.5923+x} * P_0 \quad (29)$$

Saturated steam pressure can be obtained from steam tables or calculated with formula [**51**,**53**]:

$$p_h{}' = P_0 * e^{(11.78*\frac{T-99.24}{T+230})} \quad (30)$$

Where temperature is in Celsius.

The FGC is assumed to work in near atmospheric pressure P_0 = 101325 Pa. Now, the saturated steam pressure in the outlet flue gas can be calculated from equation 30 in:

$$p_h' = 101325 * e^{11.78*\frac{52.6-99.24}{52.6+230}} = 14261Pa$$

The absolute humidity can be calculated by combining equations 21 and 28 in dew point:

$$x = \frac{0.5923*p_h{}'*\partial}{P_0-p_h{}'*\partial} \quad (31)$$

$$x = \frac{0.5923 * 14261Pa * 1}{101325Pa - 14261Pa * 1} = 0.0970\,\frac{kg}{kg, dry}$$

Enthalpy at the outlet temperature is calculated with equation 20. Now the heat capacity for vapor is Cp,v = 1.85 kJ/kgK

$$H,k2 = 1.0057\,\frac{kJ}{kg}\ (52.6℃ - \ 0℃) + \ 0.0970\,\frac{\text{kg}}{kg_{dry}} * (2501.4\,\frac{kJ}{kg} + 1.85\,\frac{kJ}{kg} * (52.6℃ - 0℃))$$

$$H,k2 = 305.03\,\frac{kJ}{kg}$$

To calculate the heat recovered we multiply the enthalpy difference with the amount of dry gas, which is m_{dg} = 43.96 kg/s:

$$P = m_{dg} * (H,k1 - H,k2) \tag{32}$$

$$P\ = 43.96\,\frac{kg}{s} * \left(588.53\,\frac{kJ}{kg} - 305.03\,\frac{kJ}{kg}\right) = 12461\ kW$$

3.2.4. Method 3 (Condensation with heat pump)

Using a heat pump, DH return water temperature directed to FGC can be significantly lowered. Let us assume that the DH return water temperature can be lowered by 10 degrees and the flue gas is in 100% relative humidity when leaving the FGC. In this case, the temperature in flue gas outlet is 42.6C. To calculate the flue gas enthalpy in the end of FGC, saturated steam pressure has to be calculated using equation 30:

$$p_h{}' = \ 101325 * e^{(11.78 * \frac{42.6 - 99.24}{42.6 + 230})} = 8641Pa$$

The moisture content is determined using equation 31:

$$x = \frac{0.5923 * 8641Pa * 1}{101325Pa - 8641Pa * 1} = 0.0550\,\frac{kg}{kg_{dry}}$$

Now the flue gas enthalpy can be obtained by using equation 20:

$$H,k2 = 1.0057\,\frac{kJ}{kg}\ (47.6℃ - \ 0℃) + \ 0.0550\,\frac{\text{kg}}{kg_{dry}} * (2501\,\frac{kJ}{kg} + 1.85\,\frac{kJ}{kg} *$$

$$(42.6℃ - 0℃))$$

$$H,k2 = 184.85\,\frac{kJ}{kg}$$

The next to step is to calculate heat the recovery with equation 32:

$$P\ = 43.96\,\frac{kg}{s} * \left(588.53\,\frac{kJ}{kg} - 184.85\,\frac{kJ}{kg}\right) = 17744\ kW$$

Coefficient of performance (COP) is used to determine the electricity used in heat pump applications. Typically, the COP number for heat pumps varies from 4 to 8 [**1**]. If the COP number is 6 the electricity consumed for this additional energy can be calculated by using equation 33 [**62**]:

$$COP = \frac{W+Q}{W} \qquad (33)$$

where

COP = coefficient of performance

W = power demand of the heat pump (kW)

Q = heat pumped (kW)

The heat pumped can be calculated with equation 10 using the average district heating water mass flow and the heat capacity of water, as described in section 3.

$$Q = c_p * m_{dh} * dT = 4.19\,\frac{kJ}{kgK} * 263\,\frac{kg}{s} * 10℃ = 11020\ kW$$

The power demand of the heat pump is derived from equation 33:

$$W = \frac{Q}{COP - 1} = \frac{11020\ kW}{6 - 1} = 2203\ kW$$

3.2.5. Method 4 (Condensation with humidification)

With CAH, the dew point temperature of the flue gas can be increased and, the heat recovery in FGC is enhanced. Humidifying is done to the combustion air, which is humidified to the saturation point. The temperature of combustion air is dependent on the DH return water temperature, because the CAH is linked with FGC water circulation. Assuming that the temperature approach is 2℃, the temperature of the combustion air is going to be 48.6℃. The saturated moisture content can now be calculated from the saturated vapor pressure using equation 30:

$$p_h{}' = 101325\ Pa * e^{11.78 * \frac{48.6 - 99.24}{48.6 + 230}} = 11707 Pa$$

The molar mass of the gas is M_{air} = 28.97g/mol, which corresponds to the molar mass ratio of 0.6213. The absolute moisture content is calculated from equation 31:

$$x_2 = \frac{0.6213 * 11707\ Pa * 1}{101325\ Pa - 11707\ Pa * 1} = 0.0812 \frac{kg}{kg, dry}$$

The average combustion air feed is around m_{ba} = 25.2 kg/s. The yearly average outside temperature is assumed to be around 5.5℃ and the relative moisture 79% (Turku). As previously, the absolute moisture is calculated from saturated vapor pressure:

$$p_h{}' = 101325\ Pa * e^{11.78 * \frac{5.5 - 99.24}{5.5 + 230}} = 913 Pa$$

$$x_1 = \frac{0.6213 * 913\ Pa * 0.79}{101325\ Pa - 913\ Pa * 0.79} = 0.0045 \frac{kg}{kg, dry}$$

Moisture content increase in the flue gas can now be calculated by:

$$m_{wi} = (x_2 - x_1) * m_{ba} \tag{34}$$

$$m_{wi} = (0.0805 \frac{kg}{kg_{dry}} - 0.0045 \frac{kg}{kg_{dry}}) * 25.2 \frac{kg}{s} = 1.93 \frac{kg}{s}$$

Moisture of the flue gas without moisturizing is m_{w1} = 6.92kg/s and now with moisturizing:

$$m_{w2} = m_{w1} + m_{wi} = 6.92 \frac{kg}{s} + 1.93 \frac{kg}{s} = 8.85 \frac{kg}{s}$$

Since the amount of dry gas stays constant (m_{dg} = 43.96 kg/s), the absolute moisture can be calculated as follows:

$$x = \frac{m_{w2}}{m_{dg}} = \frac{8.84 \frac{kg}{s}}{43.96 \frac{kg}{s}} = 0.2014 \frac{kg}{kg_{dry}}$$

The initial flue gas enthalpy is calculated using equation 20, assuming the temperature to stay constant (Cp,v = 1.91 kJ/kgK):

$$H, k1 = 1.0057 \frac{kJ}{kg}\ (149℃ - 0℃) + 0.2014 \frac{kg}{kg_{dry}} * (2501.4 \frac{kJ}{kg} + 1.91 \frac{kJ}{kg} * (149℃ - 0℃))$$

$$H, k1 = 710.89 \frac{kJ}{kg}$$

CAH also decreases the outlet temperature of flue gas, but in the calculation, this energy is already taken into account in the increased moisture content. Temperature of the flue gas outlet is assumed to be 52.6℃, and the flue gas is in the saturation point. Enthalpy in the flue gas outlet is obtained directly from the calculations for method 2:

$$H, k2 = 305.03 \frac{kJ}{kg}$$

Finally, the heat recovery is calculated using equation 32:

$$P = 43.96 \frac{kg}{s} * \left(710.89 \frac{kJ}{kg} - 305.03 \frac{kJ}{kg}\right) = 17840\ kW$$

3.2.6. Comparison of methods

Method 3 and method 4 had similar potential for heat recovery (figure 13). For the calculations of method 3, a 10 degrees drop in the DH return water temperature was considered, but in a real situation, temperature can be further decreased or changed with heat pump power input. However, a heat pump requires extra energy (steam or electricity), which affects its feasibility [**1**]. Method 2 is limited by DH return water temperature, which significantly decreases heat recovery when this temperature is high. Method 4 is more effective when the DH return temperature is high, because CAH further decreases the circulation water temperature by evaporating water to the combustion air [**1**].

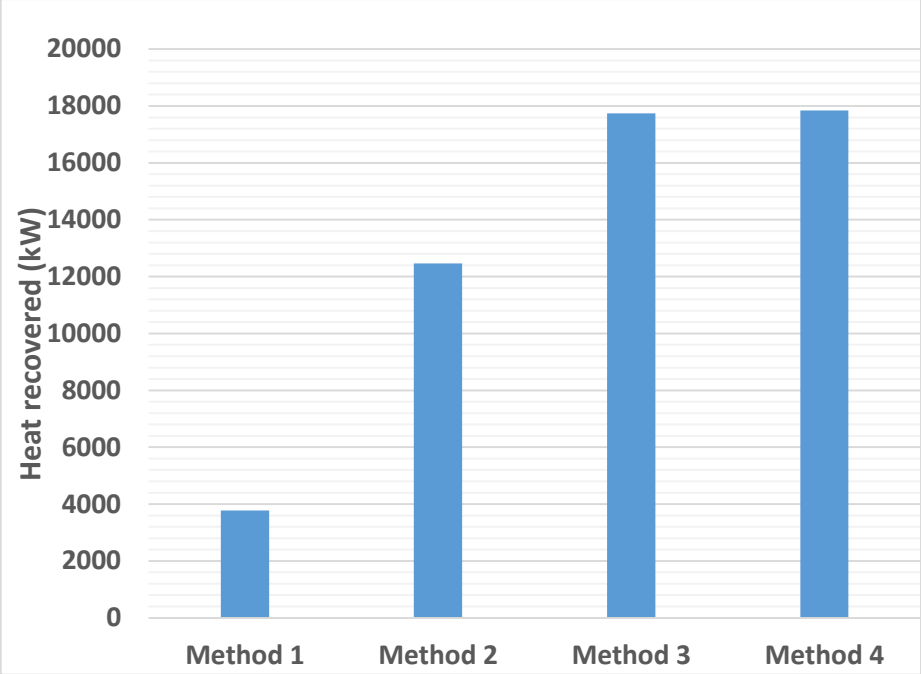


Figure 13. Heat recovery potentials of different methods.

Considering that capital costs are a function of process complexity and the number of equipment required, methods 3 and 4 are the most expensive ones. Without a specific knowledge of the investment costs, it is hard to compare costs of these two, but usually heat pumps are more expensive compared to combustion air humidification [**1**]. Method 2 can be said to be the least expensive of these three. Method 1 is the cheapest if flue gas temperature is kept above acid dew point, but its potential is also low [**55**].

*Table 10. Raw comparison of methods [**1**,**50**,**55**].*

Method 1		**Method 2**		**Method 3**		**Method 4**	
+	**-**	**+**	**-**	**+**	**-**	**+**	**-**
Cheap	Low potential	Latent heat utilization	High temperature dependence	Latent heat utilization	Cost	Latent heat utilization	Increases flue gas amount
				High potential	Needs external power	High potential	Increases combustion air amount

4. EFFECTS ON OVERALL BALANCE OF CHP PLANT

FGC have an effect on both mass and energy balance of the CHP plant. Mass balance is changed by the condensate formed as well as by water and chemicals circulating in the FGC unit. If CAH is used, also the amounts of combustion air and flue gas are increased, which effect on existing fan capacities.

One of the major things affecting the energy balance is that the FGC is the first place where DH return water is directed into the CHP plant, so the water will be at a higher temperature in the turbine heat exchangers [**1**]. By Carnot's law, the efficiency of a turbine is a function of the inlet and outlet temperatures of steam [**63**]. In the turbines, there may be two DH heat exchangers, which are driven by the DH outlet temperature. Now that the water is at a higher temperature in the inlet of first heat exchanger, the steam must condensate at a higher temperature leading to higher pressure and temperature steam. This means that the power production is decreased. Second heat exchanger is not affected by the effect, but it is affected by the decreased steam flow [**1**].

As previously calculated, the FGC with or without CAH or heat pump has significant effect on heat production. CHP plants are usually operated based on DH network thermal load or on the demand from other heat consumers. With FGC the fuel consumption decreases, because the heat demand can be met with less boiler output. Furthermore some boilers may use oil or natural gas when the heat demand is peaking, and the usage of these more expensive fuels may be significantly lowered when FGC is used. This effect is demonstrated with an example of a retrofitted CHP plant presented in table 11 [**1**].

*Table 11. Plant comparison to retrofitted FGC + CAH [**1**].*

Parameters	**Unit**	**Existing CHP plant**	**CHP plant with FGC + CAH**
Max DH supply	MW	50	70
Boiler design fuel effect	MW	81	81
Heat production	MWh/a	261000	274000
- from turbine	MWh/a	261000	205000
- from FGC	MWh/a	0	69000
Power production	MWh/a	110000	86000
Biomass consumption	MWh/a	423000	332000
Gas/oil consumption	MWh/a	29000	14000

As seen in table 11, the installation of FGC and CAH to an existing CHP plant increased the maximum district heat supply from 50 MW to 70 MW. As expected power production was cut down, but also fuel consumption was greatly reduced. Gas/oil usage in one year was less than halved, which lowered the fuel costs and made the investment more profitable [**1**].

4.1. Effects on operation efficiency

Biomass contains moisture that is turned into vapor in the boiler, which consumes energy due the phase transition. Part of this energy can be recovered with FGC. Efficiency of CHP plants in Europe, is usually calculated in LHV basis. LHV assumes the fuel water component to be in vapor state in the end, where as high heating value (HHV) approach assumes it to occur as liquid. At the optimal conditions, the efficiency of modern CHP plant can be around 85% but with FGC heat recovery efficiency can be increased to over 100% in the LHV basis [**1**].

PRACTISE PART

5. REFERENCE PLANT IN RAUMA

Reference plant for which FGC is considered is a CHP plant operating in Rauma, Finland and it is owned by Pohjolan Voima Oy's subsidiary company Rauman Biovoima Oy. The plant's production capacity for electricity is 76 MW, for process steam 140 MW and for district heat 50 MW. Process steam is delivered to nearby UPM-Kymmene Oyj paper mill and district heat is sold to Rauman Energia Oy. Electricity is fed to the grid, where it is consumed by the paper mill and Rauman Energia Oy. The plant is mainly powered by bark and forest residue, which quality is enhanced with a dryer. Also some amounts of recycled fuels and sludge are burned. The CHP plant has four boilers, HK 2, HK 4, HK 5 and HK 6, from which HK 6 is the newest, built in 2006. Boilers HK 2 and HK 4 uses heavy fuel oil and they are used only for peak loads. The environmental permit for boiler HK 2 is expiring after 2015, which will end its usage. HK 5 and HK 6 are the main boilers with a total output of 266 MW [**64**,**65**]. This thesis focuses on boiler HK 6, because the FGC is considered to be attached to this boiler, but HK 5 is also included to the plant balance calculations, because it is connected to the same turbine. In this section the reference plant is introduced in detail and the conncetions of the FGC to the steam network and to the flue gas treatment are proposed.

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5.1. Boiler HK 6

Boiler HK 6 (figure 14) is a bubbling fluidized bed boiler (BFB) with a fuel capacity of 135 MW. The fuel is mainly bark and forest residue, which is dried in a dryer. Enviromental techonlogies used are: Limestone injection, SNCR and BHF. Limestone is injected to boiler to reduce SO_2 emissions. SNCR ammonia spray is used to reduce NO_x emissions and BHF to remove fly ash particles. Enviromental permit values has been met with these techonlogies. The existing environmental technologies linked to the boiler can be seen in figure 15 [**64**,**65**].

Figure 14. Boiler HK 6 in Rauma CHP plant

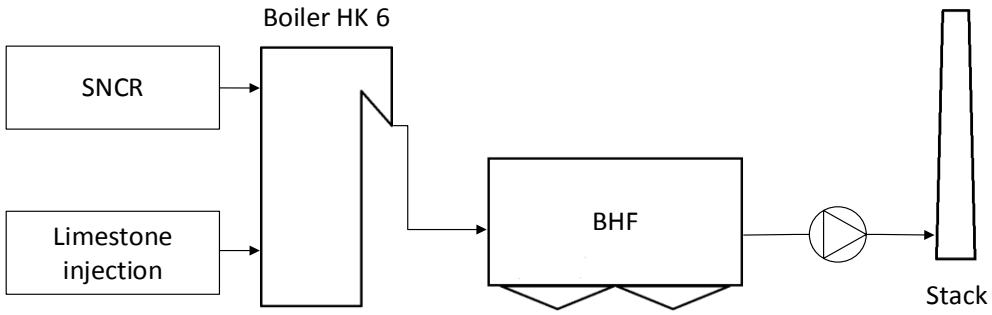

Figure 15. Current environmental techonlogies linked to HK 6.

5.2. Steam network and CHP plant runnability

Boilers HK 5 and HK 6 produce high pressure (HP) steam to turbine TG 6 and some to boiler HK 2 turbine TG 5 in peak loads. Most of the heat produced is process steam. Steam is split to 3 bar and 10 bar steams, which are used by paper mill. CHP plant is operated based on process steam and DH demand and, at the same time power is produced. Process steam is being used to produce DH when turbine heat exchangers capacities are limiting. In peak demands, a total amount of 90 MW of DH can be produced. CHP plant uses a cooler aid to cooldown DH return water when DH demand is minimal. CHP plant has also a DH accumulator to storage heat. Boilers HK 2 and HK 4 are connected to the same network, but their usage has been minimal [**64**,**65**].

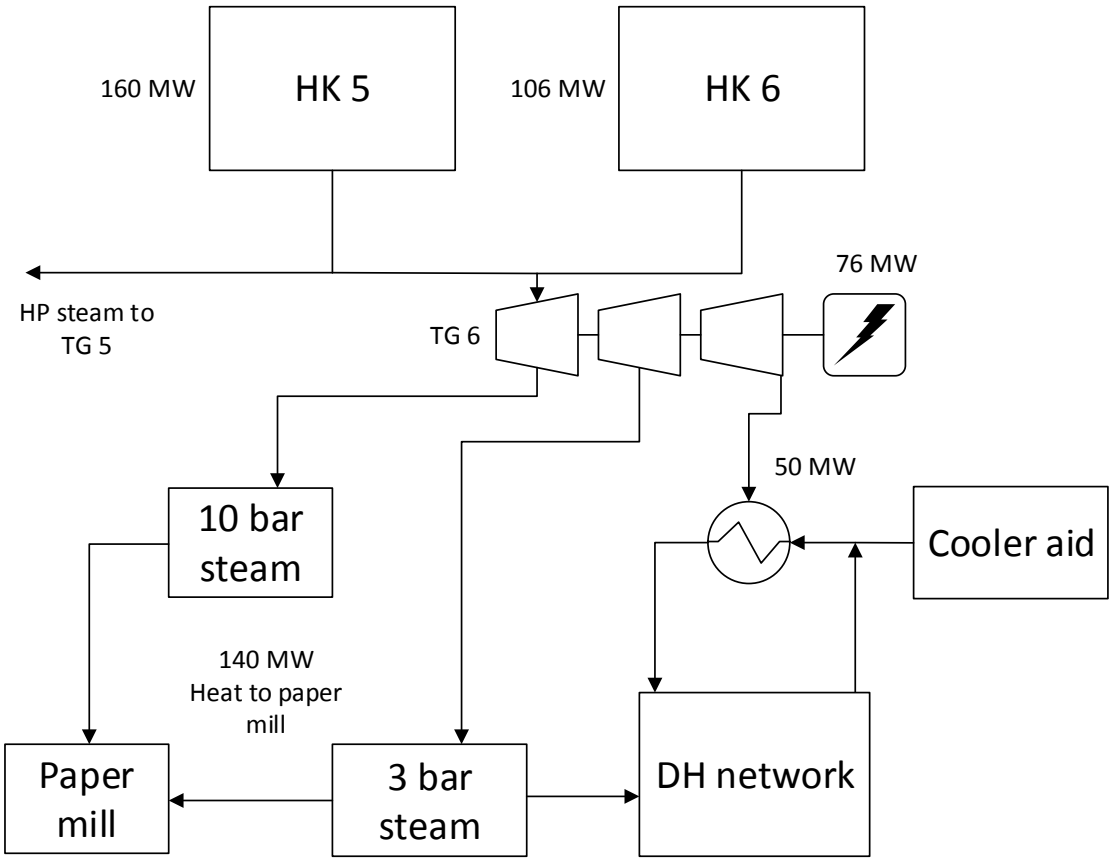

*Figure 16. Simplified scheme of boilers HK 5 and HK 6 connected to turbine TG 6 [**65**].*

5.3. DH network in Rauma

Most of Rauma Energias DH demand is produced by the CHP plant. Rauma Energia has its own boilers to meet the peak demands or when the plant is shutdown. These boilers are mainly being operated when outside temperature is below -15℃, and annually they produce a couple percents of the total demand. However, recent years have been mild, and therefore the production has been minimal. For example in the winter of 2014-2015, there were only 5 hours when the temperature was below -15℃. In the network DH return water temperature varies yearly from 40℃ to 65℃ and the temperature of DH supply water from 80℃ to 115℃. Return water is at its highest temperature in summer and winter and at the lowest temperatures in autumn and spring. Supply water temperature is highest in winter and lowest in summer. DH water flow varies from 55 liters/s to 350 liters/s, being lowest in summer and highest in winter [**20**].

5.4. FGC connected to boiler HK 6

When FGC is connected to HK 6, it should be installed after BHF and ID fan. DH return water is directed first to FGC and after that to turbine heat exchangers [**1**,**28**]. Condensate treatment can be linked so that the condensate is taken from washing or heat recovery stage waters. Storage and pump are needed for the chemical additive (NaOH for example), and this additive is directed to the FGC circulating streams. An example of how the FGC could be connected to boiler HK 6 presented in figure 17. If the goal is also to increase DH maximum capacity, the effects on DH pumps, pipings and valves needs to be considered. Other issues to consider are [**35**]:

- Stack design
- Fan capacities
- FGC bypass
- Continuos emission monitoring system (CEMS)
- Flue gas and combustion air ducting and DH water piping
- Space and layout
- Automation
- Electrification
- Instrumentation
- Foundations
- Buildings
- Drainage
- Possible dismantlements
- Environmental and construction permits

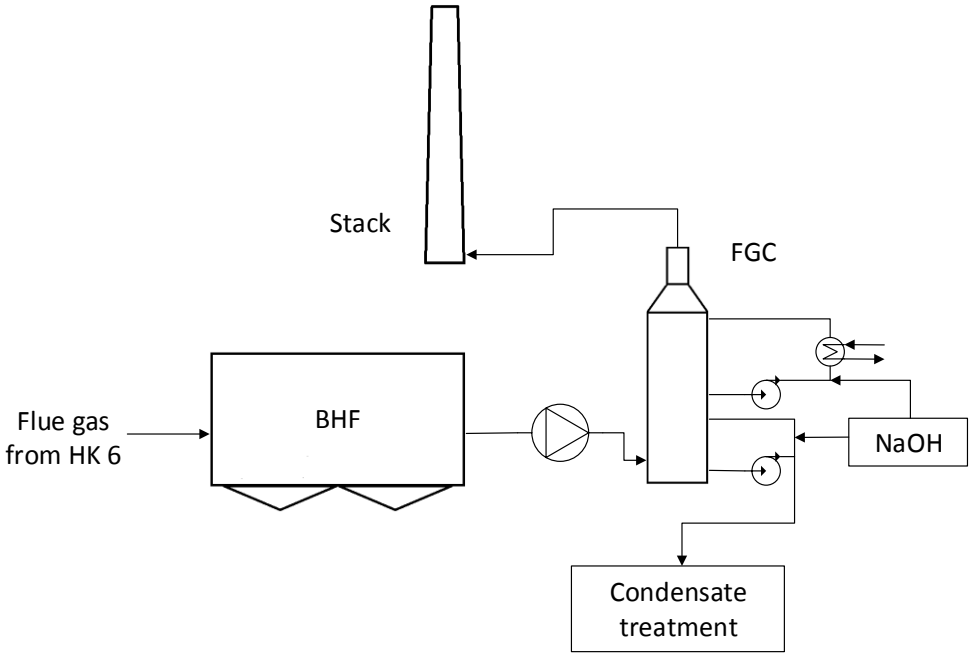

*Figure 17. FGC connected to boiler HK 6 [**28**].*

6. ENVIRONMENTAL IMPACTS

If BREF drafts latest version BAT -associated air emission limits are executed, some changes must be made, because currently boiler HK 6 cannot fulfil the new requirements, at least not those for SO_2, NO_x and HCl (table 12).

*Table 12. Flue gas emissions and current permit limits. Yearly average in 6% oxygen (28.5.2014-27.5.2015, except TOC, HF and particles, which are average values of daily measurements from a time period of 3 months) [**3,8,9,60,20,66,67**].*

mg/Nm^3	Flue gas emissions	Current permit limits	BAT-AEL
HCl	44	60	1 – 9
NO_x	206	280	50 - 180
SO_2	119	188	< 10 – 70
NH_3			3 - 15
CO	24	123	30 - 160
TOC	0.46	15	
HF	0,12	4	
Particles	0.46	25	2 - 12

If FGC unit is installed to the boiler, SO_2 and HCl emissions are estimated to be reduced as presented in table 13. With FGC, NO_x emissions cannot be lowered without a special design, and other solutions should, therefore, be considered [**68**]. These alternative solutions could include combustion optimization, flue gas recirculation and optimization of current SNCR unit [**3**].

*Table 13. New estimated and old HCl and SO_2 emissions [**8**].*

mg/Nm^3	Without FGC	With FGC	BAT-AEL
HCl	44	4.4	1 - 9
SO_2	119	9.52	10 - 70

For the problematic SO_2 and HCl, the new requirements can be met quite well with FGC. NH_3 emission levels are not being measured at the moment, but according to table 5 and 6, the FGC should be able to reach BREF drafts latest version BAT-AELs. Other emissions are also affected by the FGC, but the BAT-AELs of the latest version BREF draft are already reached with the current emission levels.

When choosing the condensate treatment technologies, the condensate quality should first be considered. Because of BHF, premises for good quality condensate pertain (table 7). Quality is affected not only by the flue gas dry treatment techonology, but also by the position of the condensate is outlet. To maximize quality, condensate should be taken from the heat recovery stage waters. This would mean that a small portion of the flow is directed from the washing stage waters to the boiler for reburning. This could be problematic for environmental authorities, so it should be well explained to get an environmental permit for the action. The advantage of this operation procedure is that, only a mild treatment is needed. However, in the BREF draft's latest version, the BAT-AELs are strict for heavy metal emissions, meaning that an ion exchange treatment is might be needed. To avoid peaks solid particles entering the ion exchange column, some kind of prefiltration is recommended. This could mean simple bag filtration. Before discharging the condensate, its temperature and pH should be controlled. Temperature could be cooled with natural water in a heat exchanger or with air in a cooling tower.

6.1. Flue gas dispersion modeling

As already mentioned, FGC affects emissions dispersion by lowering the flue gas temperature and the plume rise. Dispersion modeling of flue gas emissions is done, with FGC and without it, using the Gaussian plume model introduced in section 2.4.1. Stack exit velocity is assumed to be higher for dry stack (without FGC), because

entrainment may cause problems in wet stack (with FGC) [**5**]. The calculations are done with the assumption that plain condensation (method 2) is used and the values used for calculations are shown in table 14. Plume rise is defined for dry stack and for wet stack by checking from equations 5 and 9, which is the dominating factor: buoyancy or momentum. Buoyancy was found to be the dominating factor in both situations. The effective height is thus determined from the buoyancy plume rise and stack height above sea level. To set the zero level to ground, stack height from ground is used in equation 1 to determine the effective stack height, and only the wind speed is taken into account in the actual stack height.

Table 14. Values for the dispersion modeling.

	With FGC	**Without FGC**
Stack exit velocity (m/s)	15	25
Temperature (℃)	52	149
Plume rise (m)	12	103
Stack height above sea level (m)	85.5	85.5
Stack height from ground (m)	78.5	78.5
Stack inside diameter (m)	2.3	2.3
Outside temperature (℃)	7.5	7.5
Surface wind speed (m/s)	6	6
Windspeed at stack height (m/s)	12.7	12.7

The volumetric flow of wet flue gas and the emission concentrations are assumed to be constants. The yearly average wet flue gas volume flow of 61.1Nm^3/s is used to calculate source emission rates in table 15. A 90% reduction for HCl and SO_2 in FGC is assumed, which is relatively low.

Table 15. Source emission rates.

mg/s	**With FGC**	**Without FGC**
HCl	269	2689
SO_2	727	7272
NO_x	12589	12589
Total	13585	22550

In this scenario, a typical FGC is used, so NO_x emissions are not affected. This can be used as a reference. Emission concentrations are being investigated in a 3x10 km area, one kilometer away from stack. Concentrations are calculated with 500m intervals in x and y directions in the ground level. The situation is illustrated in figure 18.

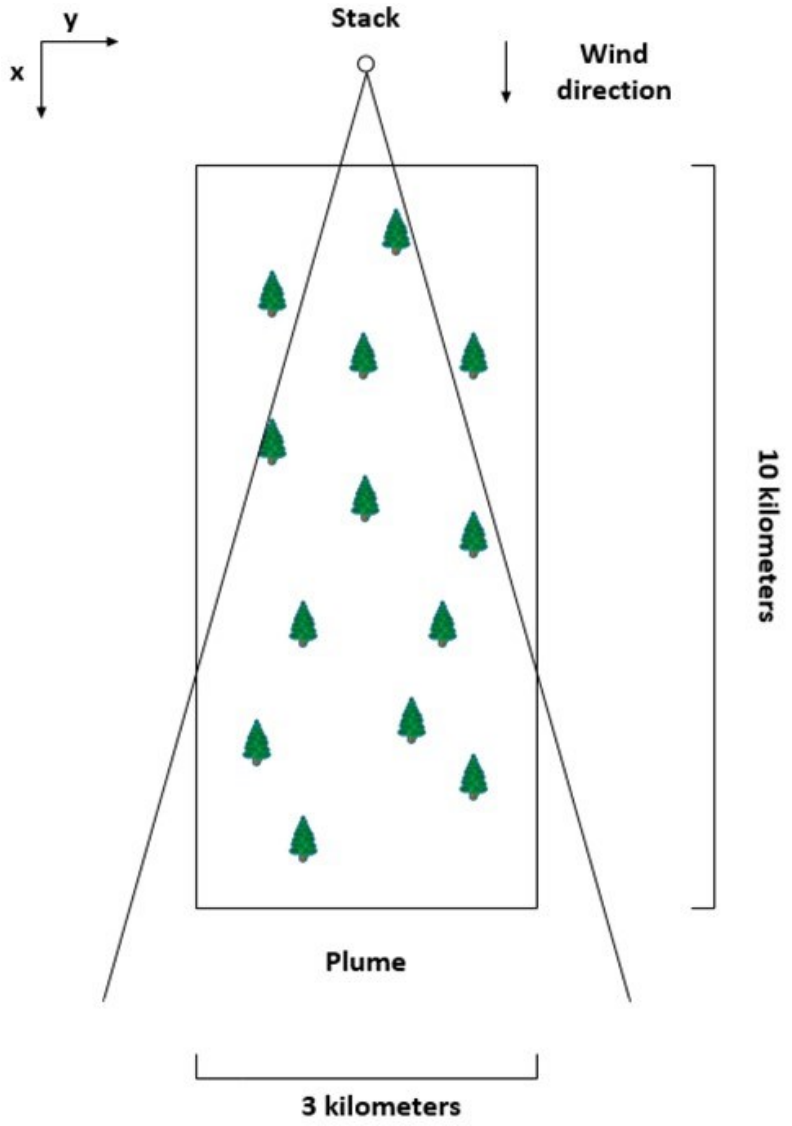

Figure 18. Plume dispersion to the area.

The emission concentrations, calculated by taking an average from each grid point for each emission, are presented in figure 19. The ground level concentrations of SO_2 and HCl are reduced significantly in the investigated area, since high emission reductions in the FGC. NO_x emissions are not affected in the FGC and now that the plume rise is

low due the low temperature, the flue gas is not spread as far and the NO_x ground level concentrations spike.

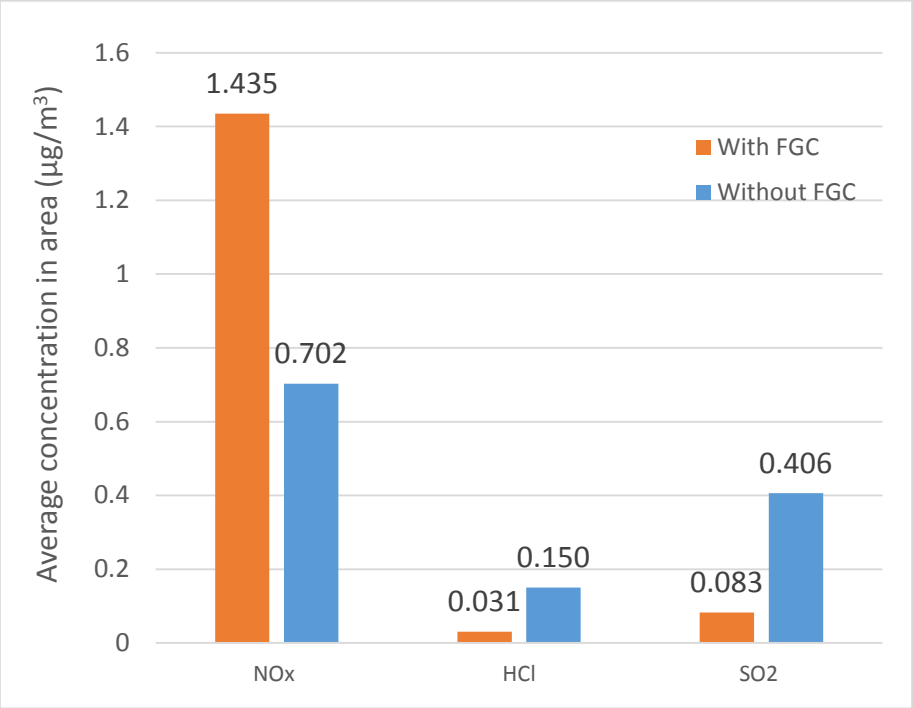

Figure 19. Average emission concentrations in the area.

To see, where most of the emissions are landing, the centerline emission concentrations are plotted as a function of distance from the stack (figure 20, 21 and 22).

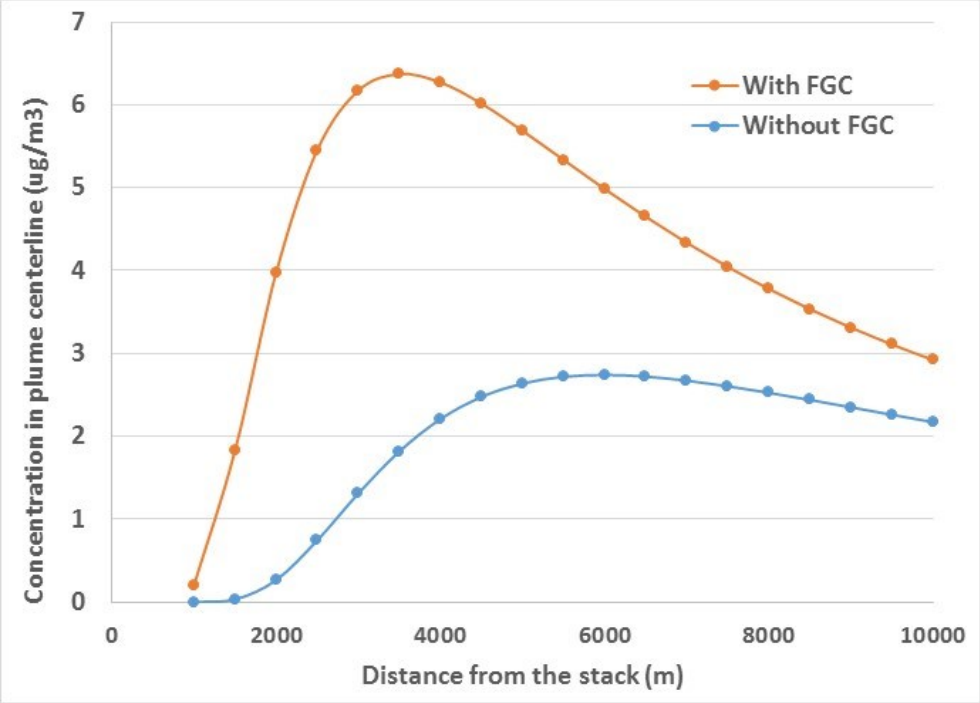

Figure 20. Plume centerline total NO_x concentration as a function of distance from the stack.

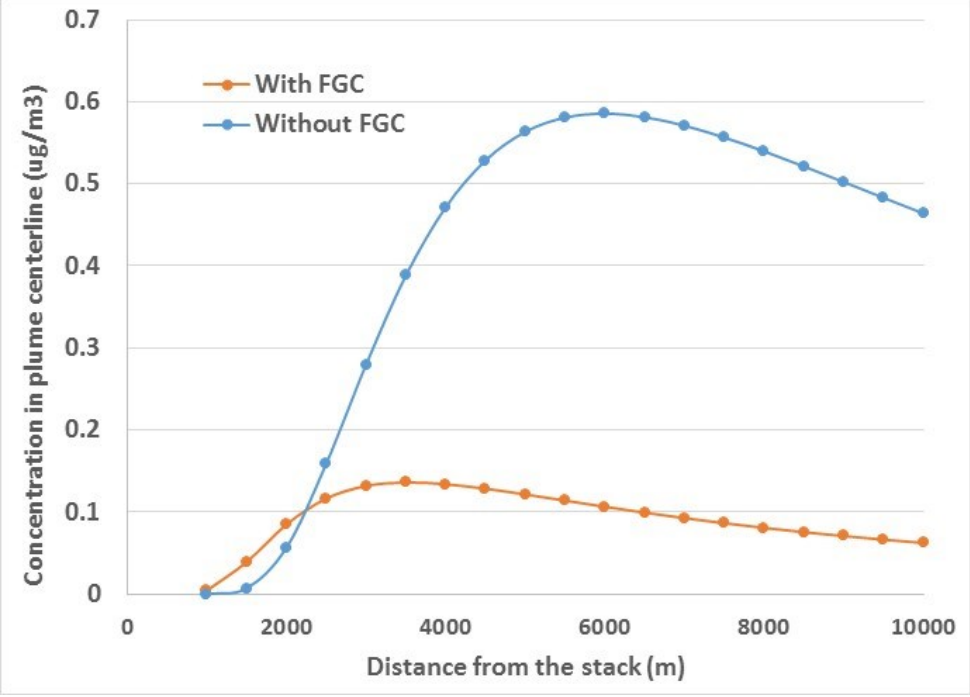

Figure 21. Plume centerline total HCl concentration as a function of distance from the stack.

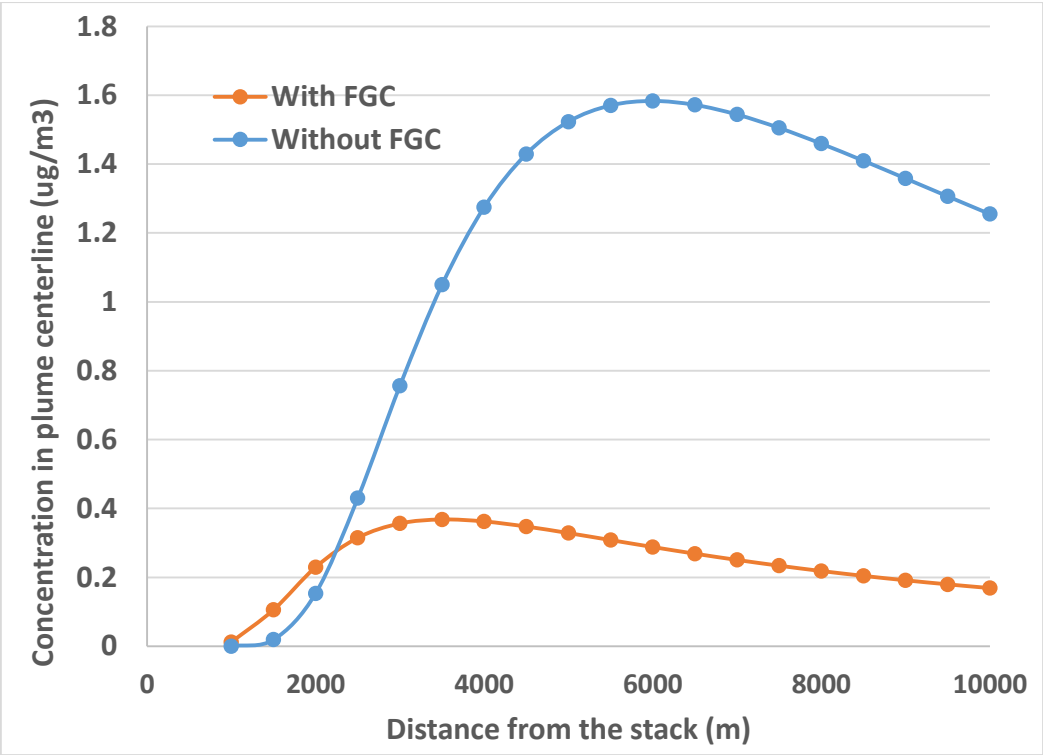

Figure 22. Plume centerline total SO_2 concentration as a function of distance from the stack.

FGC affects the emission dispersion in all the cases. Because NO_x emissions are not reduced in the FGC and the plume rise is lower due the flue gas temperature, these emissions are spread closer. SO_2 and HCl emissions are spread closer too, but they are being reduced in the FGC, resulting in lower emission concentrations in the investigated area.

7. FLUE GAS HEAT RECOVERY IN PRACTISE

In a real situation, there are many different factors affecting FGC heat recovery. These factors include variations in, for example, the flue gas amount, flue gas temperature, flue gas moisture content and DH return water temperature. CHP plant runnability is affecting the FGC aswell. As mentioned in section 5.2 the CHP plant is currently being operated by heat demand. In this section, heat recovery calculations for different

methods are done using real data, and CHP plant runnability is taken into account for time period of year. Results are then used to determine the economical aspects. Sensible heat recovery is excluded, because of its lack of relevance to the thesis topic. All the calculations are done in Microsoft Excel.

7.1. Calculation procedure

To start FGC heat recovery calculations in practise, data presented in tables 16 and 17 are needed.

*Table 16. Data collected from the CHP plant (28.5.2014 – 27.5.2015 with a 1 hour interval) [**20**].*

DH water	**Flue gas**	**Air**	**Heat to power ratios**	**HP steam**	**Efficiency**
Return water temperature	Temperature	Outside temperature	Total realized	HK 5 production	HK 5 fuel efficiency
Supply water temperature	Volume flow (Wet)	Combustion air flow	Partial curves	HK 6 production	HK 6 fuel efficiency
Volume flow	Mass flow (Wet)	Moisture content			
	Moisture content				
	CO_2 concentration				

*Table 17. Property data required for the FGC heat recovery calculations [**54**].*

Heat capacity	**Density**	**Molar mass**
Water	Water	Air
Flue gas		Flue gas
Air		
Vapor		

Plant data and property data are used to calculate the derived data listed table 18. The mass flow of DH water was calculated from the volumetric flow using water density calculated using a temperature linear correlation at a temperature that was defined as the average value of the temperatures of return and supply water. For heat capacity of water, linear correlation is used to interpolate heat capacity in average temperature between the return and supply water and this is used to calculate total DH output. The total DH output is divided for boilers HK 5 and HK 6 in the same relation with HP steam productions. Flue gas volume flow and mass flow in wet basis is used to define the density of the flue gas. Moisture content and flue gas mass flow in wet basis are used to calculate the flue gas mass flow in dry basis. CO_2 mass flow is calculated from CO_2 concentration and flue gas volume flow in wet basis. Flue gas dew point is calculated from the relative humidity via partial and saturated steam pressures. Process steam outputs are calculated from HP steam productions, DH demand and from the realized turbine heat to power ratios. Power productions are calculated from HP steam productions, DH outputs and steam outputs.

Table 18. Derived data.

DH water	Flue gas	Process steam	Power production
Mass flow	Mass flow (dry)	HK 5 output	HK 5 power
HK 5 output	CO_2 mass flow	HK 6 output	HK 6 power
HK 6 output	Density		
	Dew point		

Before the calculations, certain assumptions are made. Data collected from the boiler HK 6 shows, that outlet temperature and humidities are quite stable even though HP steam production varies. Therefore, these two properties of the flue gas are assumed to stay constant. Also, the composition of the flue gas is assumed to stay constant through out the calculation. Combustion air flow is also assumed constant, even though it varies a little with the total boiler output. CAH effect in method 4 is already included in the moisture content and the moisture content is kept constant when the boiler output varies. For Method 3, heat pump cools the DH return water by 6 MW. Previously, the heat pump effect was assumed to change the DH return water temperature always by 10 degrees, but this may lead to an unnecessarily large device, when DH water flow is peaking. This heat pump cools down the DH return water by average of 10.3℃. Also, the fuel efficiency is kept constant for each method. Process steam outputs for HK 5 and HK 6 are kept constant, because of the constant steam demand for the paper mill.

Initial situation for FGC heat recovery is calculated for each method in the same way as in section 3.2, using flue gas mass flow and by calculating the enthalpy difference from moisture content and temperature. Now the dew point limitation is considered by further iterating flue gas dew point by converting sensible heat to moisture (similarly as in the example in section 3). This action limits the FGC heat recovery so,

that DH return water can only be heated to dewpoint minus three degree (temperature approach) at maximum.

Calculation begins by considering the runnability of the CHP plant. FGC heat recovery lowers the realized CHP plant DH output. For better convergence, an initial value is needed. The initial value is chosen, so that the FGC lowers the CHP plant DH output by half of the FGC effect. When the CHP plant DH output is lowered, it lowers HK 6 DH output with same relation as HP steams are directed to turbine. Total heat production is lowered, which then affects to power production via heat to power ratios. After this, the CHP plants total output is calculated and from this, boiler total outputs can be obtained.

Now to predict change in flue gas mass flow, some kind of correlation is needed. Flue gas mass flow itself does not correlate well with the boiler total output, because the data shows that combustion air can be fed to boiler even when it is not online. For a better correlation, CO_2 mass flow could be used, because it is the main combustion product and the fuel quality is similar through out the investigated time period. The correlation is shown in figure 23.

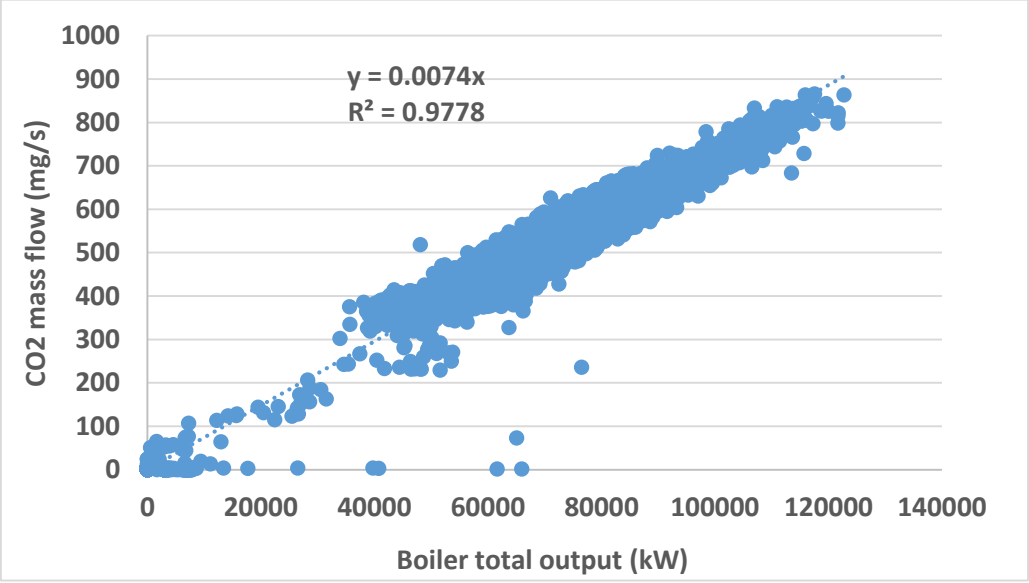

Figure 23. CO_2 mass flow correlation with boiler total output.

Using this correlation new CO_2 mass flow is obtained from HK 6 total output. This is then used to calculate new flue gas dry mass flow from CO_2 concentation, flue gas density and moisture. If the flue gas temperature and moisture is kept constant, new FGC heat recovery can be calculated by using the new flue gas dry mass flow. Next realized CHP plant DH output is reduced by FGC heat recovery and the calculation procedure starts again, forming a loop. This is repeated in iterations one to four as demonstrated in figure 24.

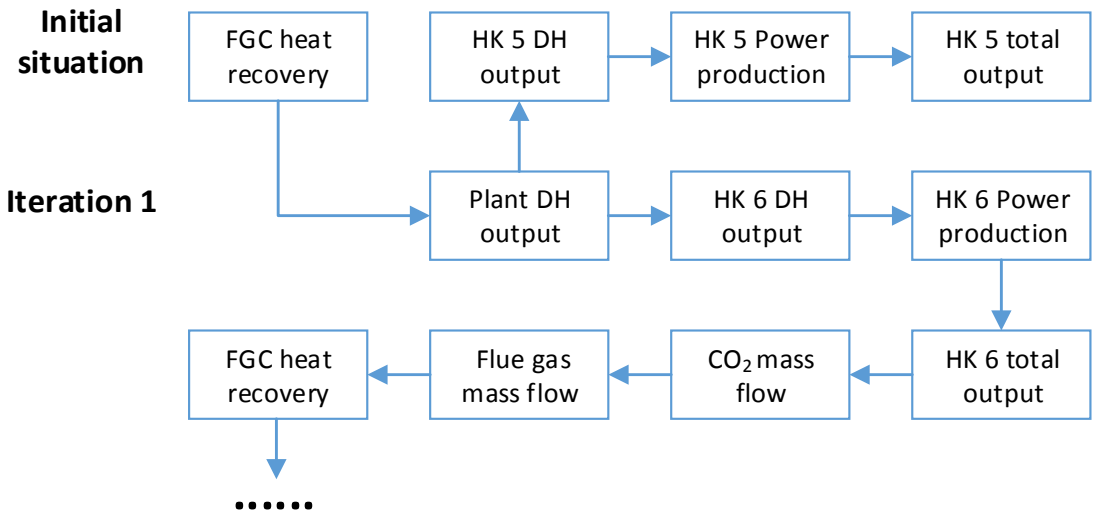

Figure 24. Calculation procedure in interations 1-4.

After four iterations, most of the points converge and the CHP plant total output is stabilized to some extent. When CHP plant total output lowers, turbine heat to power ratio lowers too. Now this is taken into account aswell. Simplification is made, so that turbine heat to power ratio is decreased in the same relation as average of all the partial heat to power ratios. This is then added to calculation procedure loop to affect power production. Partial heat to power ratios are function of turbine capacity from maximum, so that is why the CHP plant total output needed to be stabilized to some extent first. This is done in iterations five to eight as shown in figure 25.

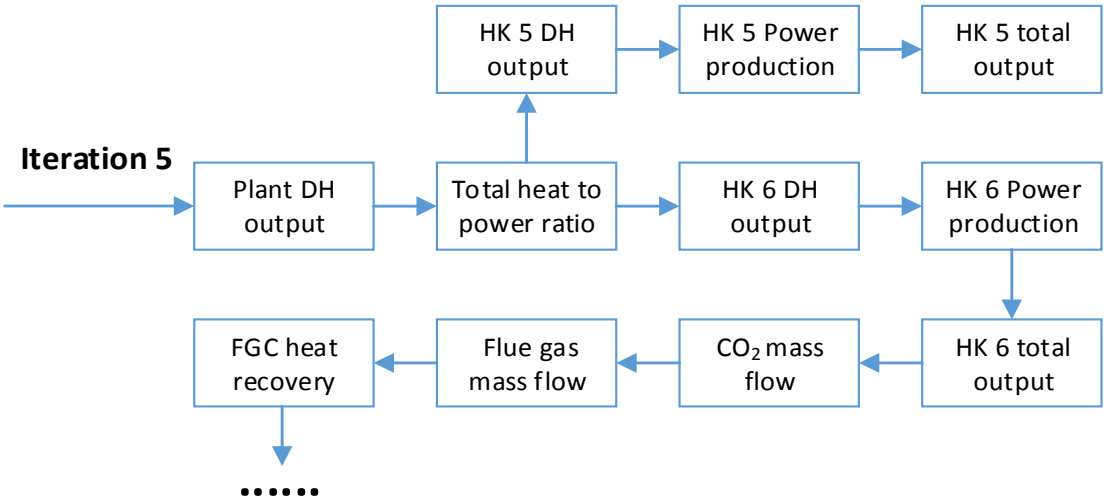

Figure 25. Calculation procedure in iteration 5-8.

This way, a raw estimate on, how the HK 6 total output and FGC heat recovery varies in real situation can be made. However for better accuracy other things need to be considered aswell. These are explained next and added to the calculation procedure.

The CHP plant is adapting two different heat to power ratios, because when the turbine DH heat exchanger capacity is limiting (40 MW), 3 bar steam is used to meet the demand, which lowers heat to power ratio by increasing 3 bar steam output. FGC lowers the turbine DH demand, so in border situations, steam could be saved and power production increased. This effect is taken into account by keeping 3 bar steam production constant and increasing the power production.

As mentioned in section 4, FGC decreases power production due to increased DH return water temperature entering to turbine DH heat exchanger. To consider this, curves for partial heat to power ratios for DH are needed. These curves are presented in figure 26.

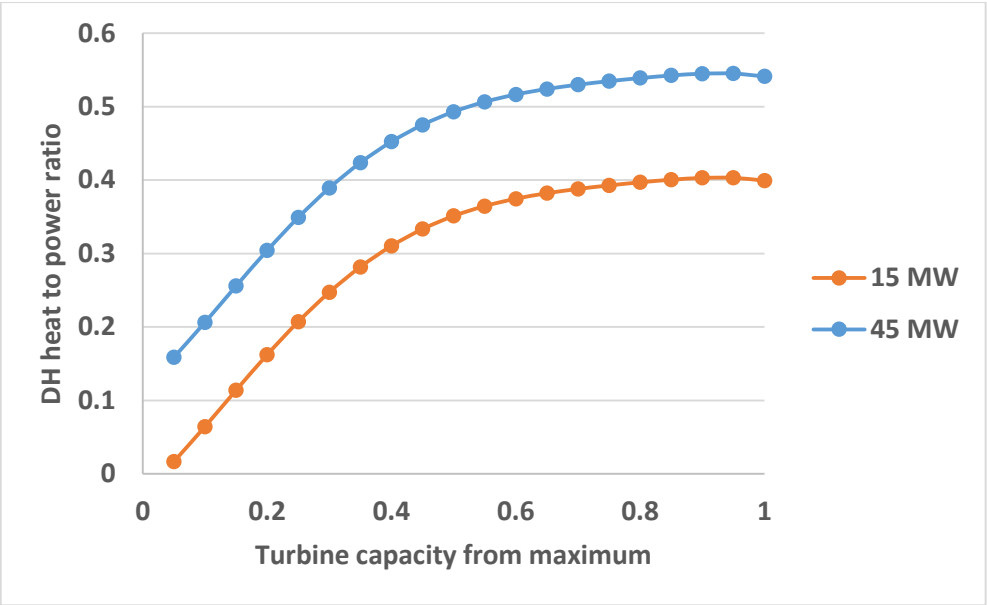

*Figure 26. DH heat to power ratio curves [**69**].*

DH heat to power ratios for different demands are calculated by linear interpolation via curves. Power production is a function of overall heat to power ratio which in further is a function of partial heat to power ratios. If steam output is kept constant, change in the power production can be calculated by comparing DH heat to power ratios with and without FGC. As mentioned, turbine capacity from maximum is changed in iteration 5 to fit the situation.

Important thing to consider is that there is a minimum output that HK 6 boiler can be operated. This output is 35 MW. This is taken into account by excluding points, when fuel usage and power production is compared to prevent impacts on economical aspects.

HK 5 and HK 6 fuel consumptions are finally calculated from HK 5 and HK 6 total outputs and fuel efficiencies. Power demand for each method is calculated from pressure drops and pumping demand. For FGC and CAH, a pressure drop of 1500kPa is used for both. Fan power demands are calculated for FGC from wet flue gas volume flow and for CAH from combustion air volume flow and situation is kept ideal. For pump power demands, 110kW for FGC and for 150kW for FGC + CAH are used.

Pressure drop values and pump power demands are got from experts from Valmet. For heat pump in method 3, COP of 6 is used for power demand calculation. NaOH usage is excluded, because it has a minimal effect on profitability calculations.

7.1.1. Method 2 in practice (Plain condensation)

Calculation procedure converges well with FGC heat recovery method 2 in practise. After four iterations, most of the points are stabilized and transition to other loop in iteration 5 goes well. After eight iterations, the calculation is finished. The convergence can be seen from figure 27.

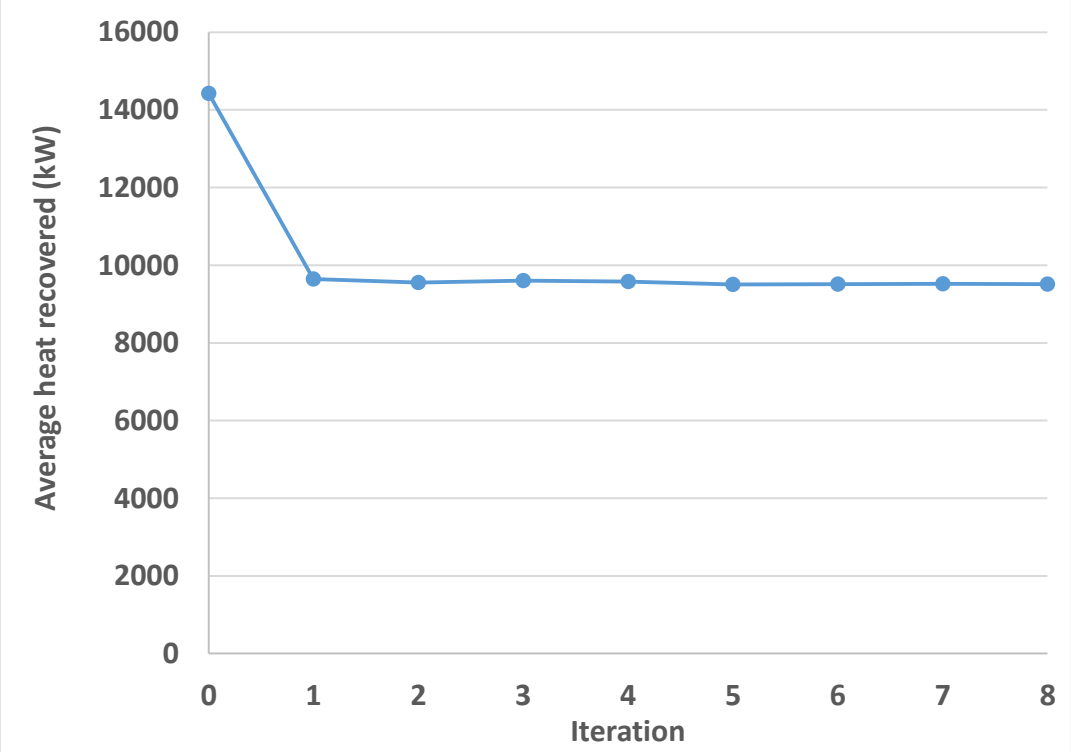

Figure 27. Yearly average heat recovered after iterations for method 2.

To make sure that runnability is considered, total DH demands with and without FGC is compared. Minimal relative error in yearly DH demands remain when comparing these two. However this does not tell, how far single points are from each other, so scatter diagram is drawn to see the hourly points (figure 28).

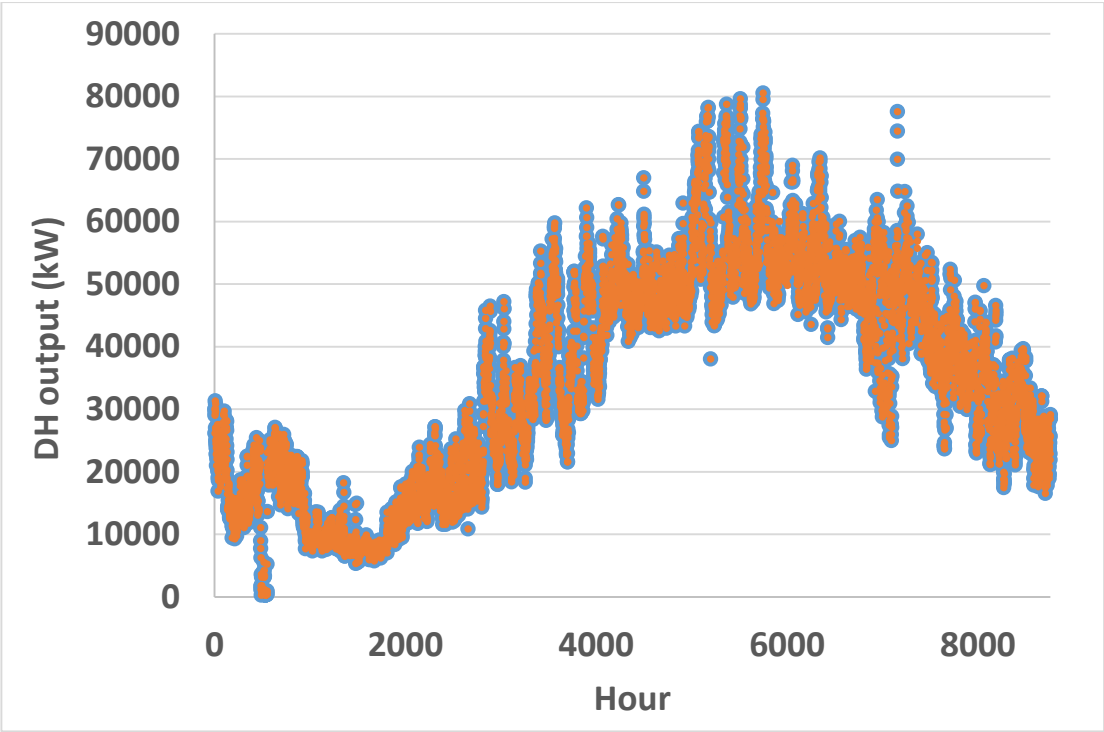

Figure 28. Method 2: DH outputs calculated with FGC (orange) and realized (blue) (0 hour = 28.05.2014 midnight).

Points fit well to each other, which verify that the calculation is successful.

Impacts of method 2 to CHP plant balance can be seen from figure 29.

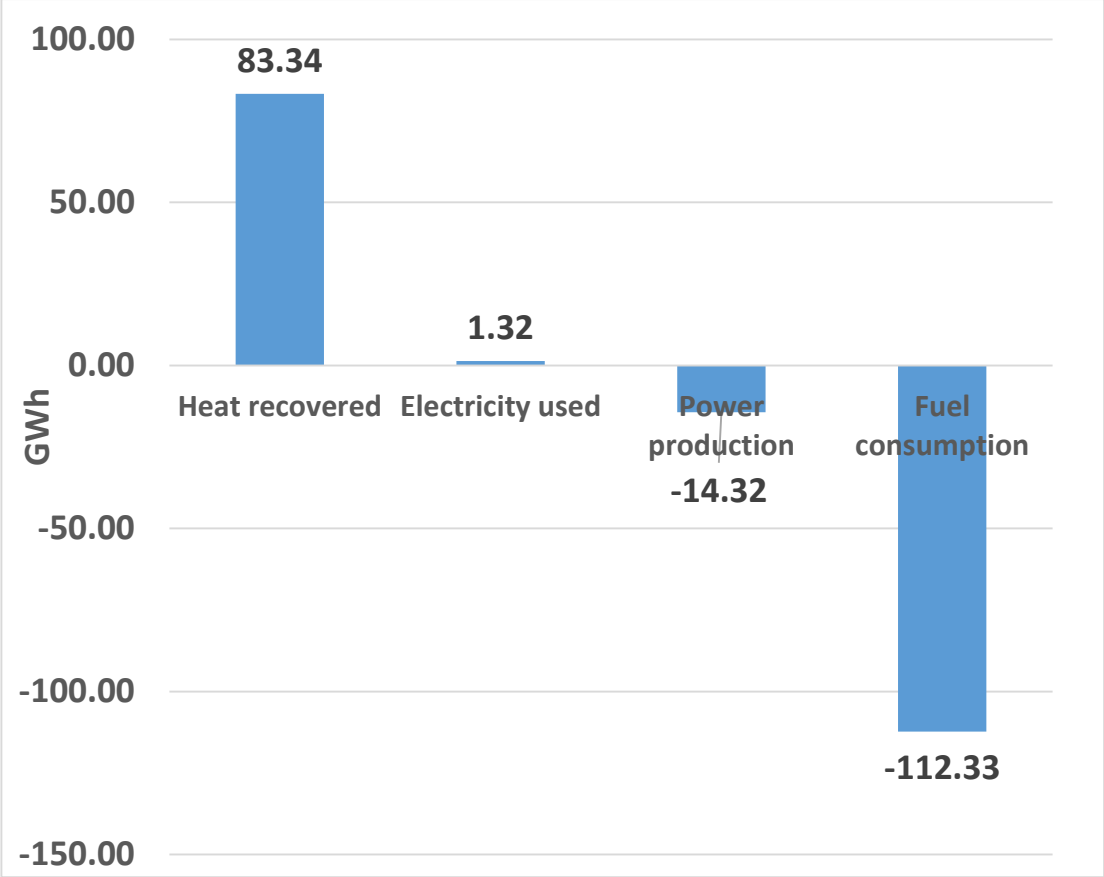

Figure 29. Impacts of method 2

7.1.2. Method 3 in practise (Condensation with heat pump)

FGC heat recovery method 3 in practice converges well (figure 30) and the loop change does not cause problems in iteration 5. After eight iterations minimal relative error remains.

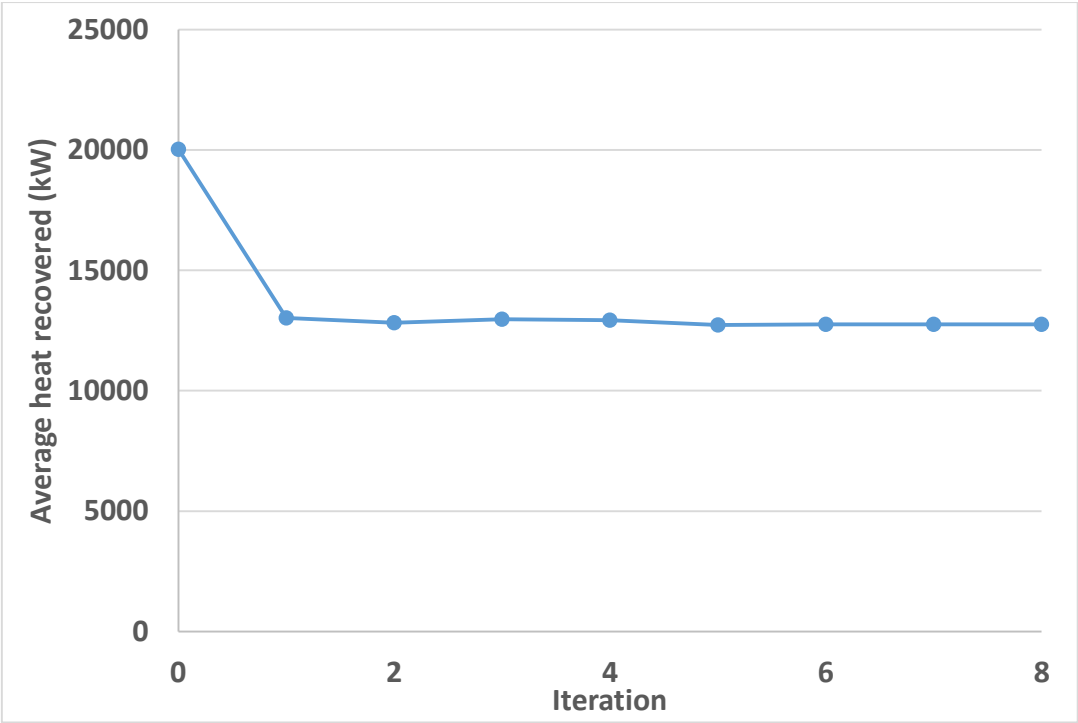

Figure 30. Yearly average heat recovered after iterations for method 3.

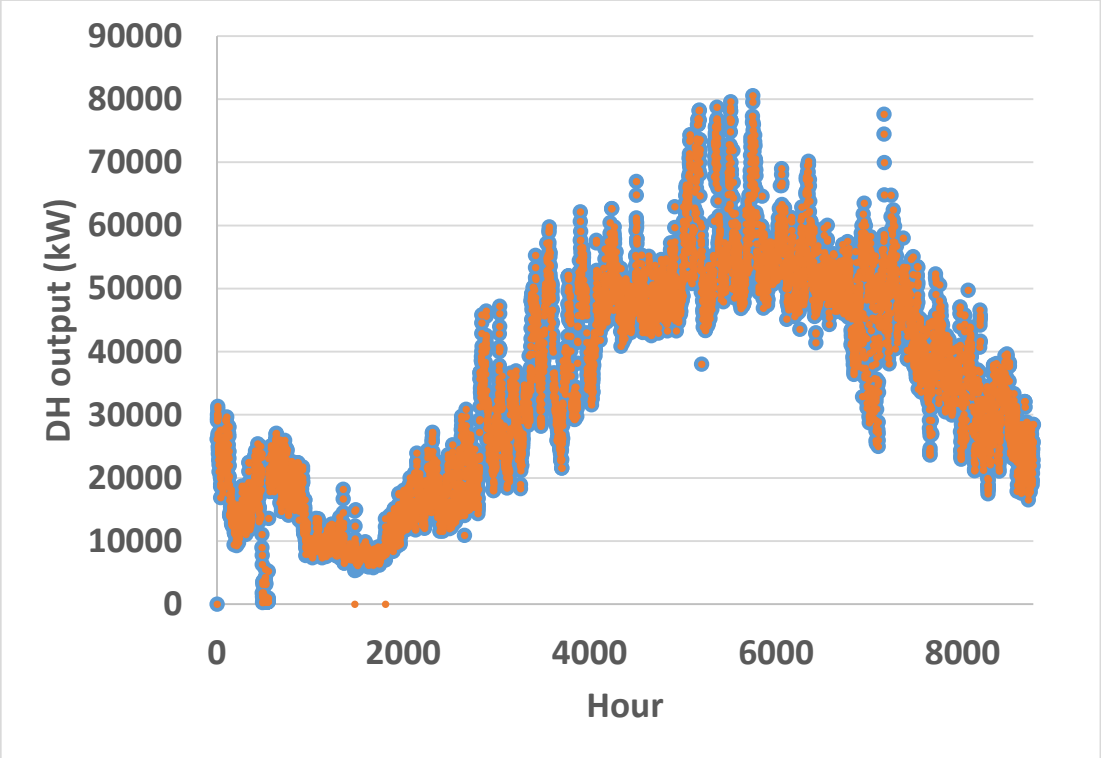

Figure 31. Method 3: DH outputs calculated with FGC (orange) and realized (blue) (0 hour = 28.05.2014 midnight).

Again, the points fit well to each other (figure 31), which verifies that the calculation is successful. Impacts of method 3 on the CHP plant balance can be seen from figure 32.

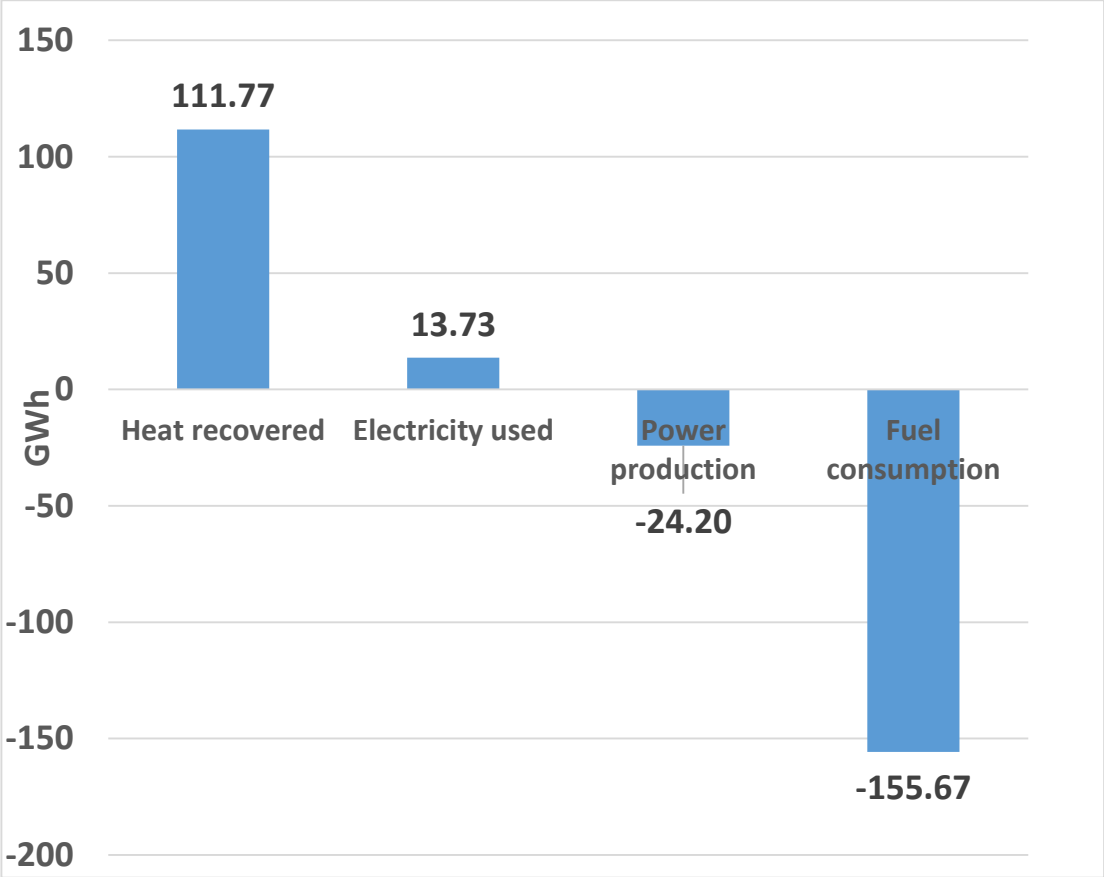

Figure 32. Impacts of method 3

7.1.3. Method 4 in practice (Condensation with humidification)

FGC heat recovery method 4 in practice converges well in iterations 1-4 and 5-8, which can be seen from figure 33. Minimal relative error remains and the points fit well to each other in point variation figure 34.

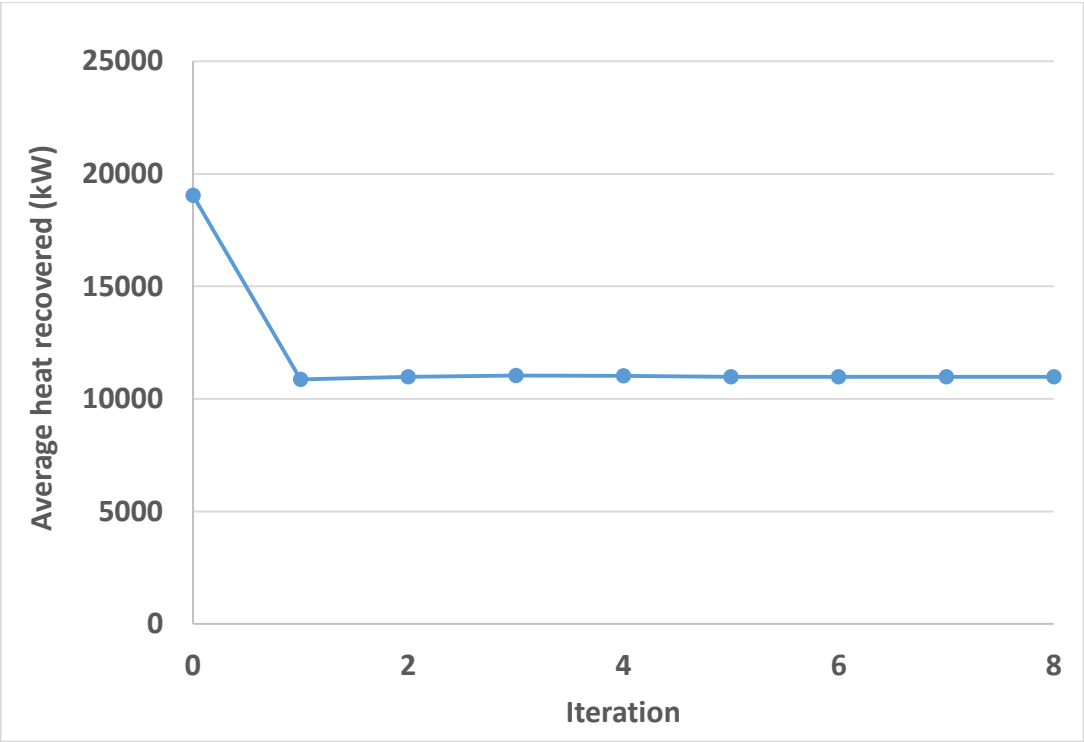

Figure 33. Yearly average heat recovered after iterations for method 4.

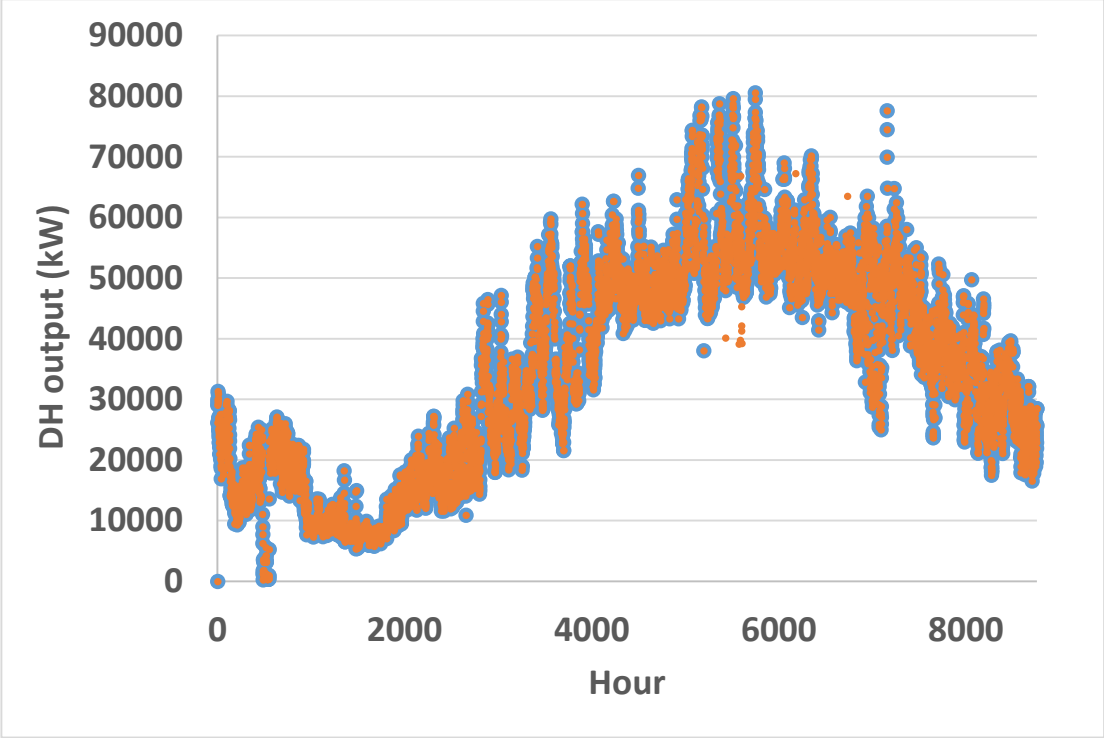

Figure 34. Method 4: DH outputs calculated with FGC (orange) and realized (blue) (0 hour = 28.05.2014 midnight).

Points fit quite well in method 4 as well. Impacts of method 4 to CHP plant balance can be seen from figure 35.

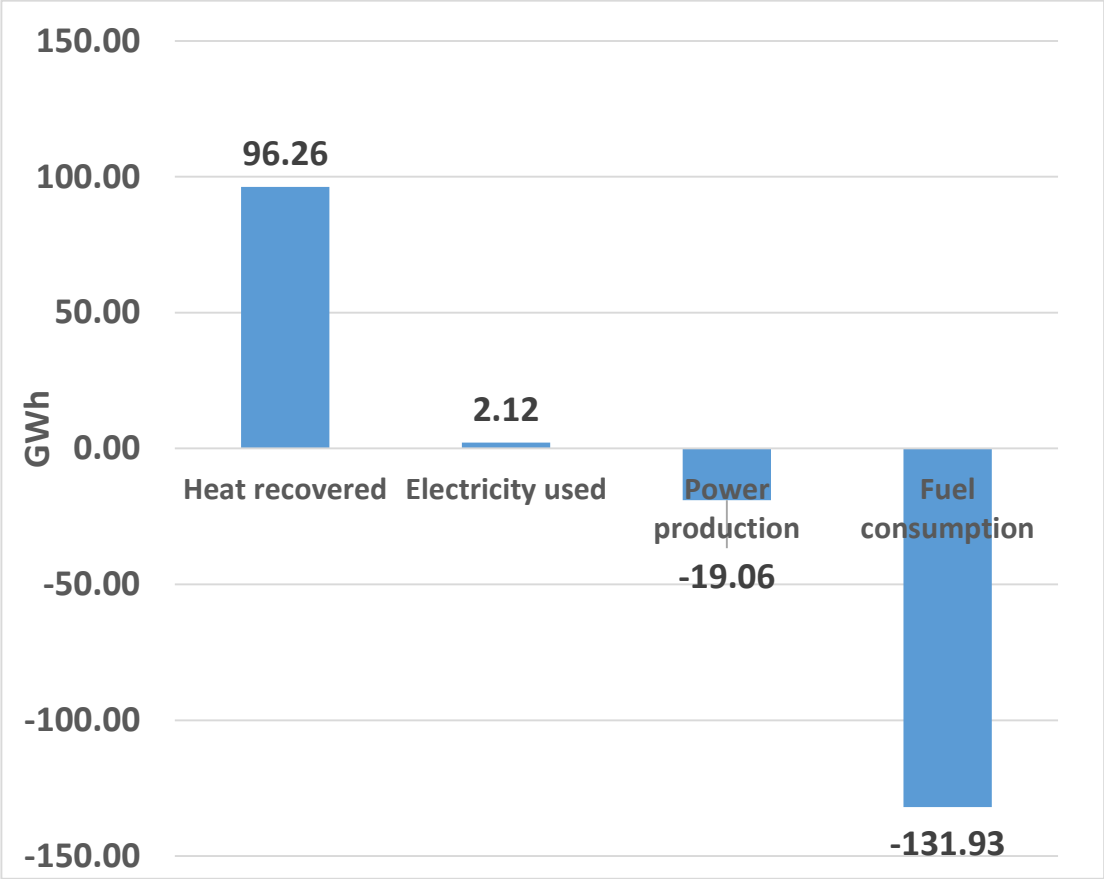

Figure 35. Impacts of method 4

7.1.4. Economy comparison

To see if FGC is profitable in the reference plant, economical parameters are investigated. These parameters include, payback time, sensitivity analysis and internal rate of return (IRR).

FGC unit costs roughly around +++ euros (table 19). For an existing boiler CAH costs around + million and heat pump around ++ euros. Other costs including automation, FGC by-pass, stack, condensate treatment, building and others are roughly estimated to be around ++++ euros.

Table 19. Prices of methods.

	Method 2	**Method 3**	**Method 4**
FGC	+++	+++	+++
Humidifier			+
Heat pump		++	
Others	++++	++++	++++
Total	+++++++	+++++++++	++++++++

In these calculations, fuel price has been 20 €/MWh. A yearly average market price for electricity for the time period can be obtained from Nordpool. A yearly average electricity price of 34.3€/MWh is used. Price of heat is excluded, because current runnability model does not increase DH sales. It is assumed that the investment is in full operation after one year of construction. The cash flows after construction can be seen from table 20. For each method, the payback time and IRR is calculated.

Table 20. Annual cash flow after construction.

	Method 2	**Method 3**	**Method 4**
Electricity	-€ 536 525	-€ 1 301 116	-€ 726 307
Fuel	€ 2 246 531	€ 3 113 490	€ 2 638 610
Total	€ 1 710 005	€ 1 812 374	€ 1 912 302

Payback time defines, how long it takes for an investment to pay itself back [**70**]. Payback time is calculated by dividing the investment by yearly net cash flow:

$$PT = \frac{IC}{NCF} \quad (35)$$

Where

PT = payback time (a)

IC = investment cost (€)

NCF = yearly net cash flow (€)

A downside for this calculation method is that it does not take into account time factor for money. The payback time results for each method can be seen from figure 36.

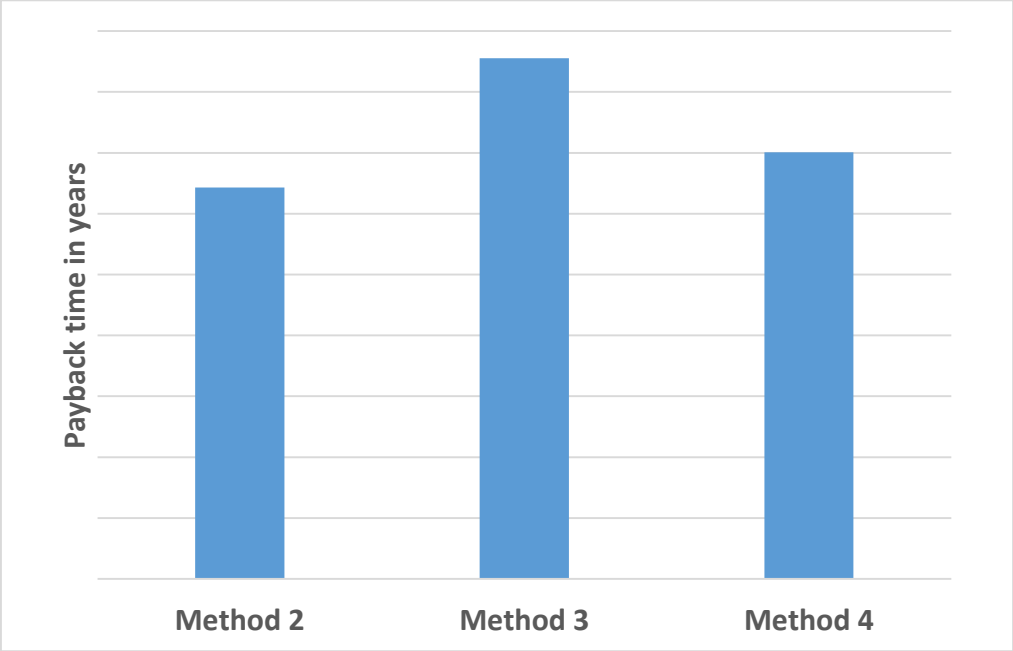

Figure 36. Payback times for each method after construction time.

Fuel and electricity price may vary over time causing risk to the investment. To see, how payback time varies with fuel and electricity price, a sensivity analysis was done [**70**]. The results can be seen from figures 37, 38 and 39.

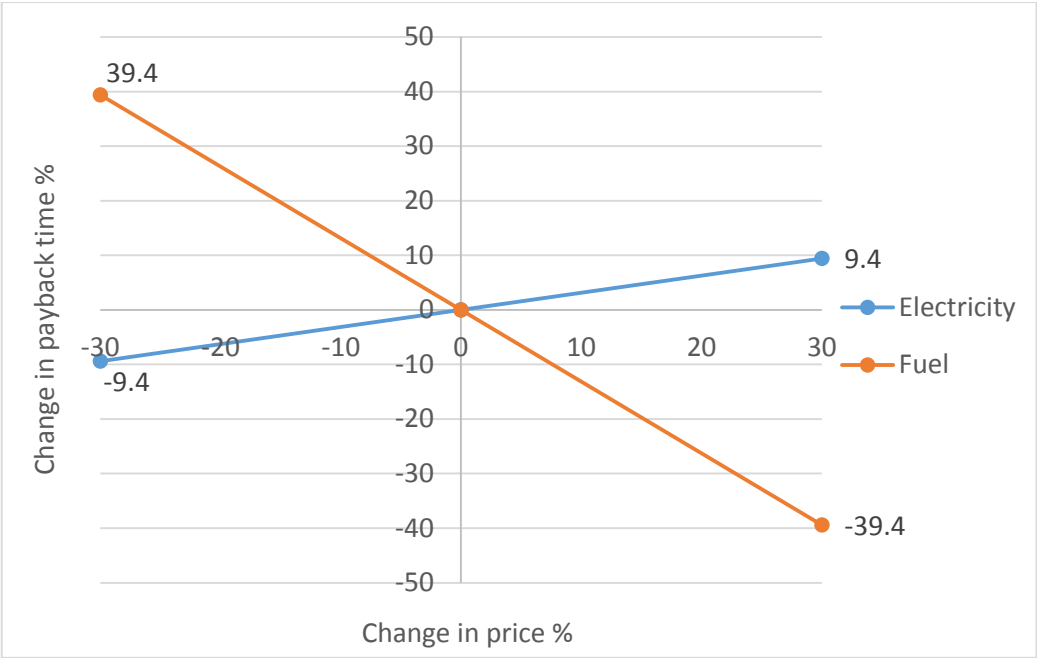

Figure 37. Sensitivity analysis for method 2.

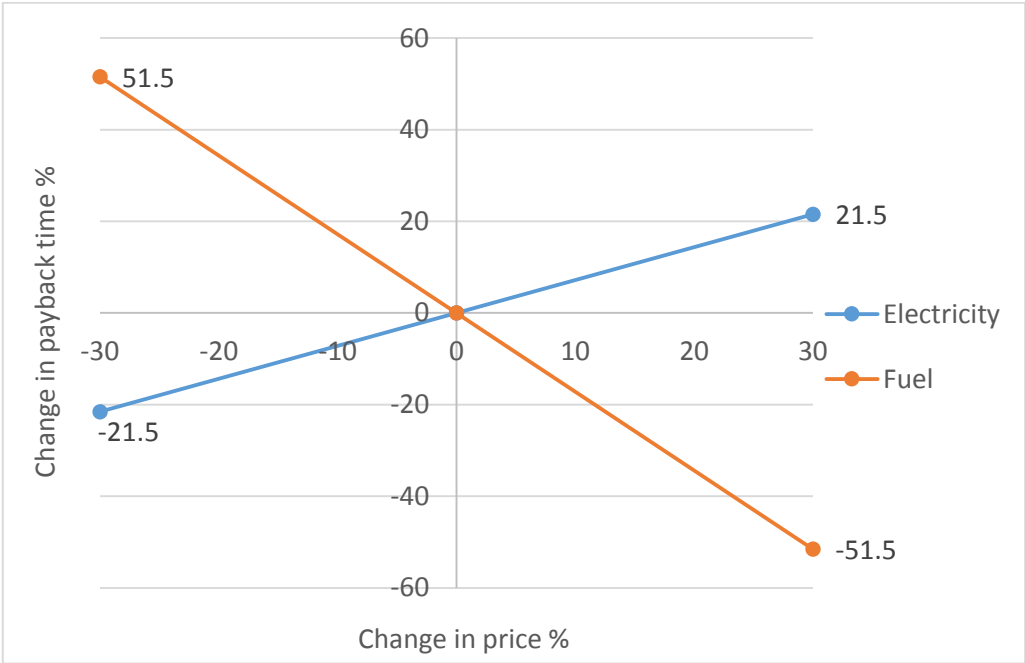

Figure 38. Sensitivity analysis for method 3.

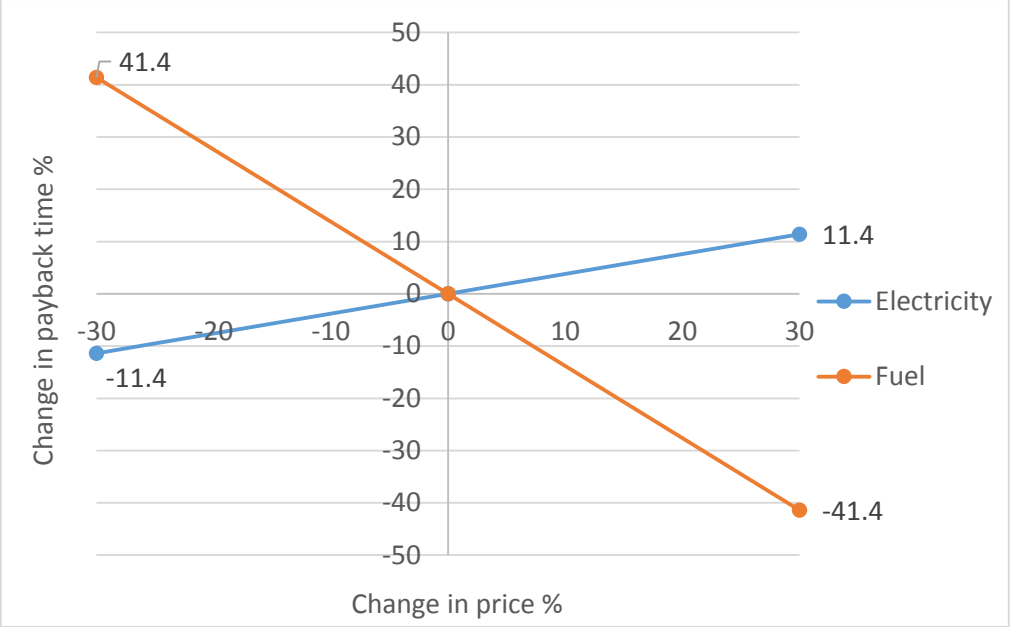

Figure 39. Sensitivity analysis for method 4.

IRR also called effective interest rate is widely used method for comparing different investment choises. It includes the time factor for money, so cash flows gained in near future are more valuable than those that are gained in far future. Factors needed for the calculation are: investment cost, yearly cash flow and time of the investment [**70**]. The formula for IRR is:

$$NPV = \sum_{n=0}^{n} \frac{C_n}{(1+r)^n} = 0 \quad (36)$$

Where

NPV = net present value (€)

C_n = cash flow of year n (€)

r = internal rate of return

Assuming the investement lasts 20 years, IRR is calculated and results are shown in figure 40.

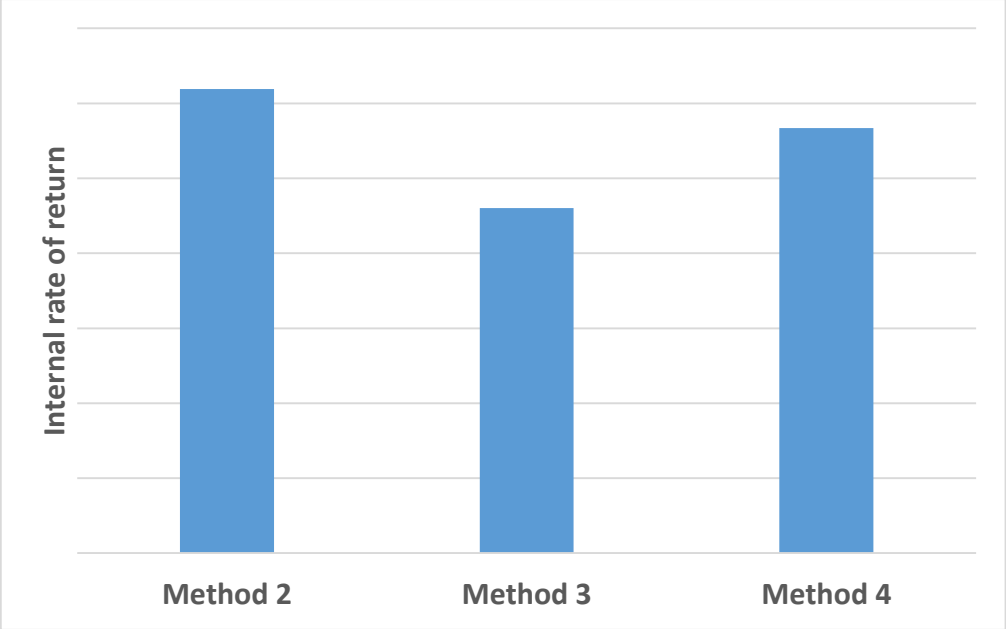

Figure 40. IRR for each method

8. RESULTS

Results of the thesis are summarized in this section. In the reference CHP plant, FGC should be put after BHF (figure 17) and connected to DH network, so that it is the first place where DH water returns. FGC unit can be either a condensing scrubber (usually 2-stage) or a tube condenser, but for the tube condenser also prewashing unit may be needed. Condensing scrubber is better for flue gases with a lot of acidic components and tube condenser for heat recovery purposes. In the reference plant, different flue gas treatment technologies are already being used and use of tube condenser could be considered.

FGC is efficient way to reduce flue gas emissions and most of BREF drafts latest version BAT-AELs for emissions to air should be reached (table 12 and 13). However, different factors, including fuel quality and other treatment technologies attached, affect the

FGC reductions. Also, for proper reductions, a chemical additive such as NaOH should be used to control pH. With FGC, NO_x emissions are not affected without a special design and other technologies such as SNCR or combustion opitimization should be considered.

Because of BHF, condensate quality is expected to be good (table 7). Quality can be maximized if the condensate is taken out from heat recovery stage, but this action is affected by environmental authorities and possible boiler limitations. Quality affects condensate treatment selection. With the expected good quality condensate relative simple technologies may be used. However, the latest version BREF requirements for water discharge are strict for heavy metals. This means that ion exchanger is probably needed. Otherwise, bag filteration may be enough. If environmental permit requires condensate temperature and pH should also be controlled. Condensate heat can be recovered to combustion air in cooling tower. Condensate can also be directed to heat exchanger and cooled with sea water or glycol water. pH can be controlled with chemical additives.

In FGC, flue gas is cooled down and saturated, which affects the stack design. To prevent stack flooding and other problems, the stack needs a droplet separation, proper drainage and insulation. Because of acidic components in the flue gas, also stack material selection needs to be considered.

Plume rise is affected by flue gas temperature and exit velocity. Temperature of the released flue gas is affected by the DH return water temperature as well as the heat pump or humidifier used. With wet stack, flue gas exit velocity is limited by the entrainment phenomena. Therefore plume rise is reduced, which leads emissions to spread closer with same stack height (figure 20, 21 and 22). However, the ground level concentrations are lower with emissions reduced in FGC.

FGC is done with three different methods, by plain condensation (method 2), condensation enhanced with heat pump (method 3) and CAH enhanced condensation (method 4). Highest heat recovery potentials are with methods 3 and 4 (figure 13). In

practice, calculations of these heat recovery methods fit well with expectations from the theory. Fuel consumption and power production are lowered with FGC (table 21). Most of the effects are focused to boiler HK 6 as they should and heat to power ratio changes act as expected. In practice most heat can be recovered with method 3, but it also uses more electricity and affects the power production and fuel consumption more than others. Heat pump is more effective than CAH when DH return water temperature is high, otherwise effects are similar. Overall it is imporant to cool down flue gas as cold as possible to increase the heat recovery.

Table 21. Effects of methods on CHP plant balance

In GWh	Method 2	Method 3	Method 4
Heat recovered	83.34	111.77	96.26
Electricity used	1.32	13.73	2.12
HK 6 Power production lost	10.25	17.07	13.06
HK 6 Fuel usage lowered	68.77	101.37	80.69
HK 5 Power production lost	4.07	7.13	5.99
HK 5 Fuel usage lowered	43.56	54.31	51.24

Heat recovery could be significantly improved, if DH return water temperature is lowered. Currently high DH return water temperature, especially during the winter peak demands, causes the heat recovery to plunge. This effect can be seen with all the methods, but it is milder for methods 3 and 4. This is why in this case CHP plants

DH production cannot be significantly improved in winter when it matters the most. This phenomenon can be seen from figures 41 and 42.

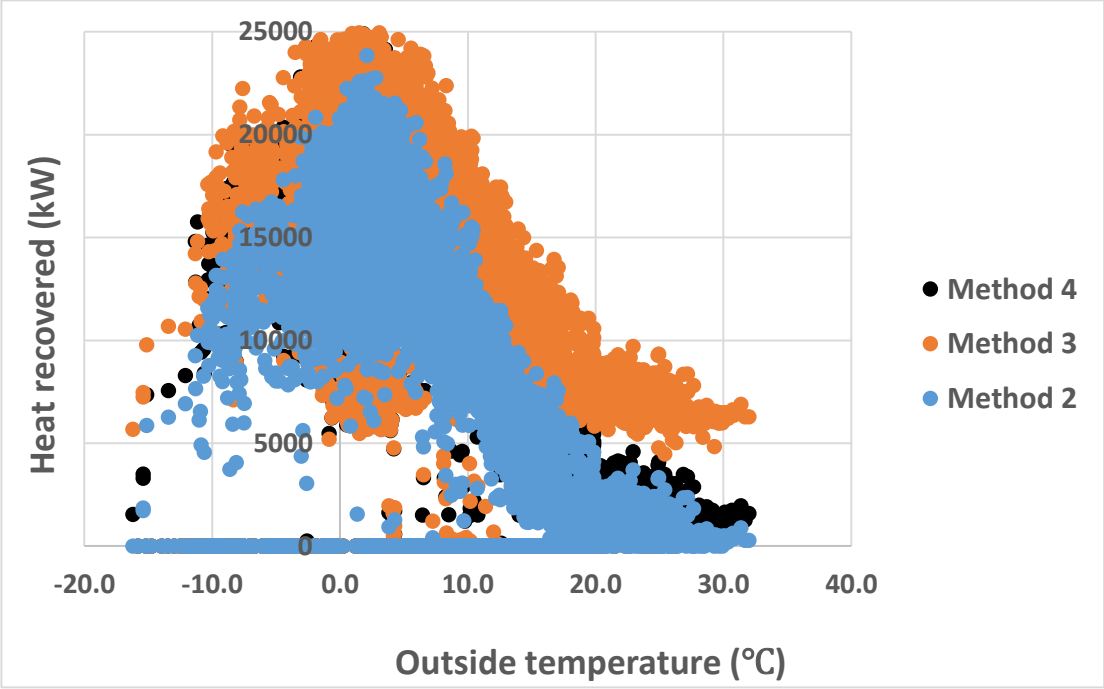

Figure 41. Heat recovery of FGC in various outside temperatures.

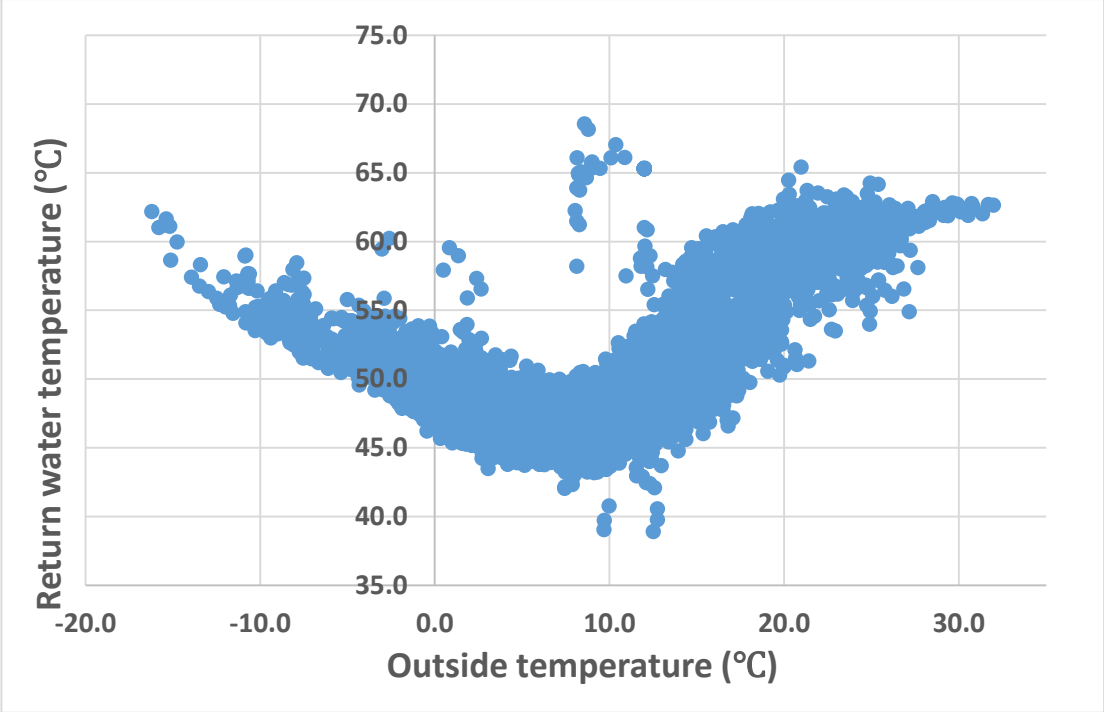

Figure 42. DH return water temperature in various outside temperatures.

Fuel efficiency of boiler HK 6 is improved by the FGC as expected. Net total fuel utilization BAT-AEEL of BREF drafts latest version can be reached with all of the methods (table 22).

Table 22. Net total fuel utilisation for HK 6 (zeroes and self usage excluded).

LHV basis (%)	Without FGC	With FGC	BAT-AEEL
Method 2	85	102	73 - 99
Method 3	85	108	73 - 99
Method 4	85	105	73 - 99

When comparing the investment costs (table 19), method 3 has the highest and method 2 the lowest cost. The highest annual income came from method 4 and the lowest from method 2 (table 20), which are derived from the effects on power production and fuel consumption. Overall, method 2 is the most profitable when payback time and IRR is evaluated (figure 36 and 40). Sensitivity analysis points out

that method 3 is the most sensitive to fuel and electricity price variations (figure 38). Methods 2 and 4 have similar sensitivity to these variations. Overall, the profitability of FGC in the reference plant is more dependent on the fuel price than on the electricity price.

9. CONCLUSIONS

In this section, the answers to the research questions defined in the section 1.1 are evaluated and furher work proposed. Enviromental impacts of FGC were studied from theoretical basis. The FGC should reduce the flue gas emissions efficiently below the latest version of BREF draft BAT-AELs for emissions to air. There are various factors affecting the reduction of emissions to air through FGC which implies that the reduction potential can only be estimated. However, the reduction is significant, because it is not only affecting the air emissions, but also the condensate quality, the stack design and the immission to the environment. Therefore, the inaccuracy of the quantitative reduction potential of FGC concerns these issues as well. Furthermore the BREF drafts emission levels are not final, and the possible changes could affect at least the condensate treatment. The FGC should be connected after the BHF in flue gas treatment procedure and, therefore the condensate quality is expected to be relatively good. This would indicate a rather simple condensate treatment. Currently, BAT-AELs for heavy metals in water discharge are strict, meaning that an ion exchanger is probably needed. Otherwise, bag filtration and condensate cooling and pH control could be enough to meet the requirements. To be sure about the condensate treatment procedure, laboratory and pilot scale testing should be done.

The applied flue gas dispersion model to calculate the distribution of the immission of air pollutants provides only a rough estimate. For better modeling, nearby buildings, yearly wind rose, emission variations and variations in atmosphere should

also be considered. Therefore, the modeling results can only be used for a guidance and far-reaching conclusions should not be made. However, with the current stack height, flue gas emissions should disperse closed, but with lower ground level concentration spike for the emissions reduced in the FGC. NO_x emissions are not affected, which in turn causes higher ground level concentration spike closer to the stack.

Flue gas heat recovery could be done with four different methods. With sensible heat transfer (method 1), plain condensation (method 2), condensation enhanced with heat pump (method 3) or condensation enhanced with humidification (method 4). In the thesis, combinations of these methods were not studied. Potentials for these methods are calculated in section 3.2 by means of the ideal gas law and with various assumptions regarding yearly average conditions. The validity of the assumptions can be accurately evaluated when the actual heat recovery unit is installed. Plant runnability, dew point and DH return water limitations were also excluded from the potential calculations, meaning that the potentials in figure 13, can only be used as a guidance. Cons and pros of these methods are compared roughly in the table 10 based on the theoretical calculations. Method 1 is excluded from the thesis after the comparison, because of its lack of relevance to the topic.

Literature shows that the FGC should be the first place, where DH return water is directed in the reference plant. Effects of FGC to CHP plant overall balance and operations were investigated in theory and in practice with calculations. These effects are highly CHP plant and year specific, because of differences in fuel/steam/DH capacities, DH network and runnability and therefore the results cannot directly be adapted to other CHP plants. However, calculations shows that changes in heat-to-power ratios, DH output and fuel consumption affects power production are in line with the expectations. Also dew point and DH demand limitations work as they should. Overall the calculations show that the FGC lowers fuel consumption, power production and the turbine DH output (table 21). The FGC affect not only the energy

balance, but also the mass balance by creating new condensate and chemical additive streams.

The full potential of FGC in the reference plant cannot be obtained since the FGC heat recovery is highly dependent on the DH return water temperature, which rises in Rauma DH network in cold days, meaning that the heat recovery is significantly decreased (figures 41 and 42). During colder year, effects of other boilers would have an effect to DH network and this effect to FGC should be investigated. However, considering only the issues that were relevant in the studied time period and acknowledging the assumptions made in calculations, it can be concluded that the FGC is an efficient and profitable way to reduce emissions from the boiler HK 6 in the reference CHP plant.

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